NERA
ECONOMIC CONSULTING

AESO Bulk and Regional Tariff Design: Expert Report

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1. Section 1 - Introduction

1.1. Overview

1. We have been requested by Norton Rose Fulbright Canada LLP, counsel to the Alberta Electric System Operator ("**AESO**"), to provide our expert opinion on our Recommended Rate Design for the Bulk and Regional Tariff ("**the Recommended Rate Design**").[1] We attach our full instructions in Attachments "1A" and "1B".

2. The AESO plans transmission investments to accommodate flows of in-merit energy and demand growth. However, the AESO's Current Rate Design for the Bulk and Regional Tariff ("**the Current Rate Design**") recovers the majority of transmission costs through a charge levied on coincident peak, irrespective of whether the transmission costs were incurred to accommodate demand or flows of in-merit energy.

3. In our Report, we examine the drivers of transmission investments in Alberta. Our analysis suggests that high utilization of transmission lines occurs at times other than coincident peak, and therefore that the Current Rate Design overstates the importance of coincident peak in driving transmission costs. Therefore, the Current Rate Design sends an inefficient price signal to users of the grid to avoid consumption at peak times because it overstates the importance of peak demand in driving transmission costs. Consequently, we find that the Current Rate Design can be made more cost reflective.

4. Our Recommended Rate Design improves on the Current Rate Design by explicitly classifying the significant costs associated with the investments to accommodate flows of in-merit energy, and recovering those costs through a cost-reflective charge levied on energy consumption. Our Recommended Rate Design sends more cost-reflective price signals to users of the grid, encouraging more efficient usage of the grid in Alberta.

1.2. Statement of Qualifications

5. This Report is submitted by Mr. Richard Druce, Director; Dr. Laura T. W. Olive, Associate Director; and Dr. Michael Dawes, Consultant; of NERA Economic Consulting ("**NERA**") which is a global economic consulting firm headquartered in

1 The Bulk and Regional Tariff ("**Bulk and Regional Tariff**") describes the transmission rates that the AESO uses to recover total wires costs functionalized to the bulk and regional systems. We refer to these bulk and regional costs as Non-Point-Of-Delivery ("**Non-POD**") costs, as they are not functionalized to Point-Of-Delivery ("**POD**").

New York, New York, U.S.A. Mr. Druce and Dr. Dawes are based in NERA's London Office located at Marble Arch House, 66 Seymour Street, London, W1H 5BT. Dr. Olive is based in NERA's Boston Office located at 99 High Street, 16th Floor, Boston, MA 02110.

6. Mr. Druce holds an M.Phil. degree in Economics from St Catharine's College, University of Cambridge, and a B.Sc. degree in Economics and Econometrics from the University of Bristol. Mr. Druce has 15 years of experience in the energy and utility industries. He has particular experience in the design and assessment of energy network tariffs and network and infrastructure access rules, the determination of utilities' allowed revenues, and the economic analysis of competitive electricity markets. Prior to this engagement, Mr. Druce has advised utilities on reforms to transmission tariffs in Great Britain, worked with transmission companies to design transmission tariffs in Oman and Saudi Arabia, and developed a transmission charging regime for the Gulf Cooperation Council Interconnection Authority. Mr. Druce has also worked with transmission network companies on regulatory topics such as cost assessment and comparative benchmarking.

7. Dr. Olive holds a Ph.D. in Economics from Northeastern University and a B.A., summa cum laude, from Simmons College, majoring in Economics and minoring in Public Policy. Dr. Olive has nearly a decade of experience in analyzing the regulation and economics of energy infrastructure. Prior to this engagement, she has supported clients in the gas and electricity transmission and distribution sectors with regard to changing market dynamics, tariff design, incentive regulation, and cost recovery methods.

8. In preparing this Report, Mr. Druce and Dr. Olive have been supported by Dr. Dawes. Dr. Dawes holds a Ph.D. in Economics from the University of Oxford, a M.Sc. in Economics for Development from the University of Oxford, and a B.A. in Economics from the University of Cambridge. Prior to this engagement, he has supported clients on the design of both electricity transmission and other regulated electricity tariffs in Great Britain and the Middle East.

9. Curricula Vitarum for Mr. Druce, Dr. Olive, and Dr. Dawes are provided in Attachment 2.

1.3. Acknowledgement of Independence

10. We acknowledge that we have a duty to provide opinion evidence to the Alberta Utilities Commission that is fair, objective, and non-partisan.

1.4. Purpose and Structure of the Report

11. We have been instructed to prepare this Report which provides our expert opinion on the following matters:

A. NERA's Recommended Rate Design for the Bulk and Regional Tariff including our underlying quantitative analysis and rationale to reach our Recommended Rate Design;

B. Key alternative design options that we considered in coming to our Recommended Rate Design;

C. A discussion of marginal and embedded rate design methods, including the appropriateness of using either method for transmission rate design in Alberta;

D. A discussion of the principle of cost causation and other relevant rate design principles, including an assessment of how the our Recommended Rate Design and the alternatives do or do not meet these principles, as well as confirmation that our Recommended Rate Design supports the AESO's published tariff design objectives; and

E. An updated cost causation (i.e., cost allocation) study (collectively, the "**Report**").

12. The Report sets out our expert opinion on the above matters using the following structure:

A. In Section 2, we set out our understanding of the context for electricity transmission provision in Alberta, including details of the legislative framework in Alberta pertinent to the Bulk and Regional Tariff. We also set out our understanding of the AESO's approach to transmission planning.

B. In Section 3, we describe the Current Rate Design, and examine recent trends in transmission charges. We also analyze factors influencing Bulk and Regional transmission costs, and discuss the extent to which these factors are reflected in the current design.

C. In Section 4, we set evaluation criteria which we use to evaluate alternative methodologies to set the Bulk and Regional Tariff. As instructed, our criteria conform to the AESO's published tariff design objectives which are consistent with generally accepted tariff design principles in other jurisdictions.

D. In Section 5, we explain marginal cost and embedded cost approaches to transmission rate design, and explain their appropriateness for the context in Alberta. We recommend that the AESO retain the current embedded cost approach rather than adopt a marginal cost approach, and instead improve the Current Rate Design to better implement the cost causation criterion described in Section 4.

E. In Section 6, we outline our Recommended Rate Design, and explain the qualitative and quantitative analysis that led us to this design on cost causation principles, and we provide details of the key alternative design options that we considered against these same principles.

F. In Section 7, we provide a summary of our Recommended Rate Design and assess the design against our evaluation criteria. We also summarize our analysis of the expected customer response to our Recommended Rate Design.

G. In Appendix A", we outline our calculation of tariffs using our Recommended Rate Design in 2019.

1.5. Summary of Opinion

13. The Current Rate Design recovers a large proportion of costs from a charge levied on coincident peak demand in each month ("**12CP**"). We understand the AESO must plan the system to accommodate all flows of in-merit energy under normal system operating conditions, and has accordingly planned investments to accommodate both demand growth and changes in the flows of in-merit energy. The significant costs associated with the investments to accommodate flows of in-merit energy are not explicitly reflected in the Current Rate Design, instead being recovered through 12CP, and therefore we conclude that the Current Rate Design could be made more cost reflective.

14. We considered using a marginal cost approach in our Recommended Rate Design. Economic theory shows that marginal cost prices may send more efficient signals to consumers regarding the impact of changes in load on the costs of transmission.

However, we concluded that the theoretical benefits of a marginal cost approach could not be realized in the Alberta context, because transmission rates cannot materially differ based upon the location of load on the transmission system.

15. Therefore, we determine that the embedded cost approach better fits within the legislative framework and characteristics of the Alberta transmission system. Based on our analysis of the drivers of transmission costs, we recommend a number of improvements to the current embedded rate design, intended to ensure it reflects the drivers of transmission investment in Alberta.

16. In the first step of our Recommended Rate Design, the AESO classifies non-POD costs between those associated with demand and those associated with accommodating flows of in-merit energy.

17. Given that generation connects at both bulk and regional system voltages and that the AESO's planners adopt a holistic view that does not distinguish planning solutions purely on the basis of line voltage, we recommend that the AESO should classify costs between demand and accommodating the flow of in-merit energy prior to functionalization of costs into bulk and regional system costs. This is because high voltage assets that meet demand reflect bulk system needs, while lower voltage assets that meet demand reflect regional needs. On the other hand, assets associated with accommodating flows of in-merit energy do not systematically vary in purpose by voltage. We recommend that the AESO:

A. Utilizes a minimum system approach to classify costs between demand and those associated with accommodating the flow of in-merit energy. We recommend that the minimum system be defined to reflect the size of the transmission system required to meet peak load in Alberta. Recognizing that the AESO's planning standards require it to plan a congestion free system under normal operating conditions, we recommend the full actual system be defined to identify the size of the transmission system required to accommodate the flow of in-merit energy in all hours. The size of the minimum system defines the proportion of costs classified as demand-related, while the difference between the actual and minimum systems defines the proportion of costs classified to accommodating the flow of in-merit energy.

B. Uses metered peak load and peak generation in each planning area in the reference year to estimate the size of the minimum and actual systems.

18. Using our recommended methodology and metered load and generation data in the AESO's planning areas in 2019, we calculate that approximately 59 percent of costs should be classified as demand-related, and approximately 41 percent of costs should be classified as those associated with accommodating the flow of in-merit energy.

19. After classification, we recommend that the AESO functionalize the pool of demand-driven costs using a similar method of functionalization as under the Current Rate Design, by using the net book value of assets delineated by voltage. We recommend functionalizing demand-driven costs using voltage to identify whether they are serving a bulk or regional function, because:

A. As higher voltage lines (240 kV and above) are more likely to be used to transmit power in bulk over long distances, between distinct areas of the system, the capacity requirement and costs of 240 kV lines are predominantly driven by demand at times of coincident system peak.

B. Lower voltage lines (below 240 kV) are scaled to meet non-coincident peak demand within a regional system, connecting those sites and planning areas to the bulk system.

20. Based on the AESO's calculation of cost functionalization in 2019, we functionalize 68 percent of demand-related costs as bulk and the remaining 32 percent as regional.[2] We apply this functionalization to the pool of demand-driven costs that we classified using our recommended minimum system approach.

21. However, we recognize that the bulk system may need to be larger than that required to meet demand at times of system coincident peak, if peaks in demand in individual areas occur at other times. The costs associated with the additional bulk transmission assets that the AESO plans to meet this non-coincident peak demand is still demand-driven,

2 AESO, Appendix-E-Transmission-System-Cost-Causation-Study-2018-Update-Workbook xlsx, Sheet "Func Results 2019", Cells "D102-F102".

but driven by non-coincident peaks in demand instead of coincident demand across the province. We therefore recommend that the AESO allocates bulk system, demand-driven costs between coincident and non-coincident demand-drivers as follows:

A. Uses metered load data to identify non-coincident peak demand in each planning area, and the maximum of each area's contribution to monthly coincident peak demand across the year.

B. Sums each areas' non-coincident peak and maximum demand during times of system coincident peak demand across all planning areas.

C. Calculates the ratio between province-wide coincident peak and the sum of all areas' non-coincident peaks. This ratio determines bulk system demand-driven costs associated with meeting coincident peak demand. The remaining costs are associated with non-coincident peak demand.

22. Undertaking this calculation using 2019 data, we calculate that approximately 93 percent of bulk system, demand-driven costs are associated with coincident peak demand, and 7 percent of bulk system demand-driven costs are associated with non-coincident peak demand.

23. After allocating bulk system, demand-driven costs there are four pools of costs to recover from billing determinants:

i. Costs associated with the accommodation of the flow of in-merit energy;

ii. Regional system demand-driven costs;

iii. Bulk system demand-driven costs associated with coincident peak; and

iv. Bulk system demand-driven costs associated with non-coincident peak.

24. We recommend recovering the four pools of costs through three billing determinants:

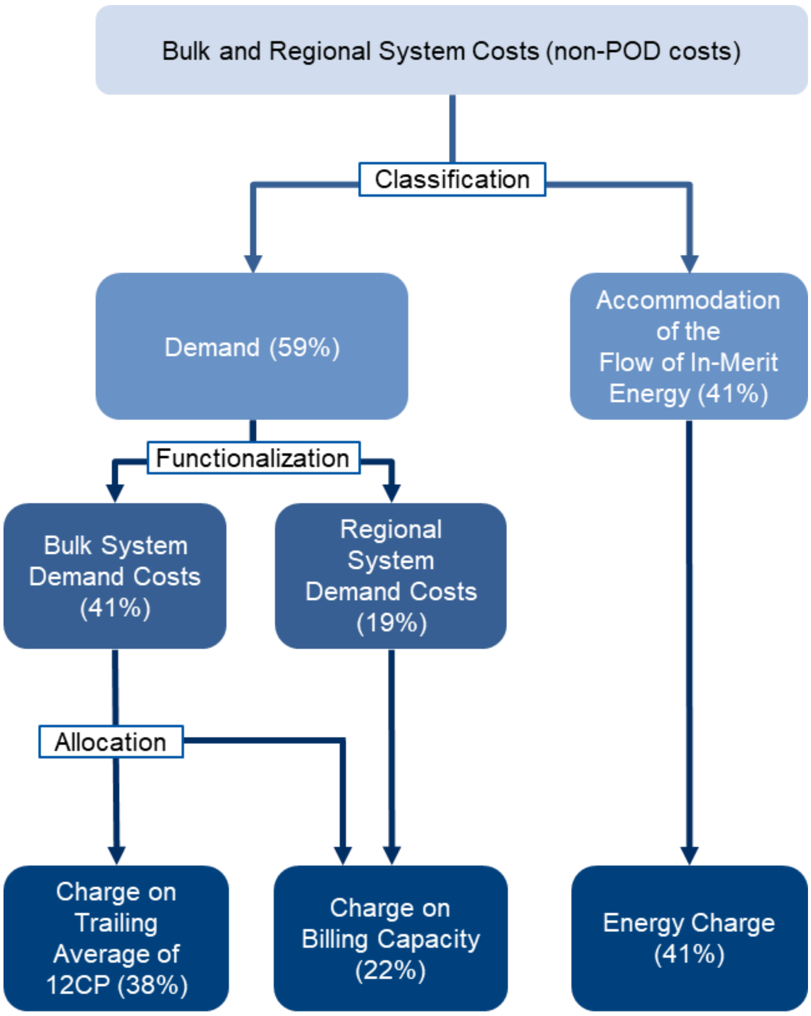
A. Recovering bulk system costs associated with coincident peak demand using a 12CP billing determinant, including five-year trailing average to the charge to reflect that sustained high consumption at times of coincident peak are more likely to drive transmission costs.

B. Recovering the remaining demand-related costs using a charge levied on billing capacity, as defined under the Current Rate Design, in order to reflect cost causation by varying with both a customer's actual non-coincident peak demand as well as the customer's option to draw up to its contract capacity.

C. Recovering the costs associated with accommodating the flow of in-merit energy using a flat, all-hours energy charge. This approach promotes economically efficient decisions by customers over whether to consume power from the wholesale market, which requires the AESO to transport electricity over its grid and relieve congestion.

25. The steps required to calculate our Recommended Rate Design, as well as the percentage of costs allocated in each step (based on 2019 data) are reflected in Figure 1 below.

Figure 1: Summary of Our Recommended Rate Design



Note: Percentages calculated using 2019 data. Components do not sum to 100 percent due to rounding. Source: See Attachment 3A for Calculations.

26. Using 2019 billing determinants, we calculate the resulting charges using our Recommended Rate Design in Table 1.

Table 1: Summary of Charges Under Our Recommended Rate Design Using 2019 Billing Determinants

Recommended Rate Design	Units	2019	% of Non-POD Costs+
12 CP Charge*	$ per MW-month	5,894	(38%)
Billing Capacity Charge	$ per MW-month	2,119	(22%)
Energy Charge	$ per MWh	10.20	(41%)

** Note: 12CP charge is levied on a five-year trailing average of 12CP but calculated using the same 12CP billing determinant as used under the Current Rate Design.*
+ Percentages do not add up to 100 percent due to rounding.
In order to ensure comparability with the rates set under the Current Rate Design in 2019, we calculate the charges under our Recommended Rate Design using the same non-POD cost revenue requirement and forecast billing determinants that the AESO used to calculate rates in 2019.
Source: See Attachment 3A for calculations.

27. Our Recommended Rate Design better meets our tariff evaluation criteria relative to the Current Rate Design. More specifically:

A. The Current Rate Design does not reflect the investments that the AESO plans to accommodate the free flow of in-merit energy. This is corrected in our Recommended Rate Design.

B. Our Recommended Rate Design better reflects principles of cost causation and thereby sends more efficient price signals to customers relative to the Current Rate Design.

C. We assess that our Recommended Rate Design does not create significant disruption to customers as the structure of charges is similar to the Current Rate Design. Moreover, any changes in the relative size of charges compared to the Current Rate Design result from moving to a tariff design that better reflects the costs of providing transmission in Alberta.

D. Our Recommended Rate Design is also more flexible – in the sense that it better reflects changes in how the transmission system is used over time – and simpler to implement for the AESO than the Current Rate Design. We classify and allocate costs based on metered load and generation data that reflects actual use of the system.

As the metered data changes between tariff years, the classification of costs in the tariff will vary to reflect that change.

2. Section 2 - Background and Context

28. As the Independent System Operator ("**ISO**") for Alberta, the AESO manages the dispatch of generators in the competitive energy-only market, plans and operates the transmission network, and procures ancillary services. The Alberta interconnected electric system is interconnected with neighbouring systems through three "interties" with British Columbia, Saskatchewan, and Montana.[3]

29. The AESO uses the "**ISO tariff**" to recover the approved costs of the regulated transmission system, ancillary services, and its own costs from customers connected to Alberta's transmission system.

30. The transmission system in Alberta is formed of approximately 26,000 km of transmission lines owned primarily by nine Transmission Facility Owners ("**TFOs**"):[4]

    A. AltaLink Management Ltd. (Privately Owned) ("**AltaLink**");

    B. ATCO Electric Ltd. (Privately Owned) ("**ATCO Electric**");

    C. ENMAX Power Corporation (Owned by the City of Calgary) ("**ENMAX**");

    D. EPCOR Distribution & Transmission Inc. (Owned by the City of Edmonton) ("**EPCOR**");

    E. City of Lethbridge;

    F. City of Red Deer;

    G. TransAlta Corporation;

    H. FortisAlberta Inc.; and

    I. Alberta PowerLine L.P.

31. TFOs are responsible for building, operating, and maintaining transmission facilities in their respective geographies. The AESO is responsible for identifying the need for

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3 AESO, 2020 Long-term Transmission Plan, January 2020, p. 22.

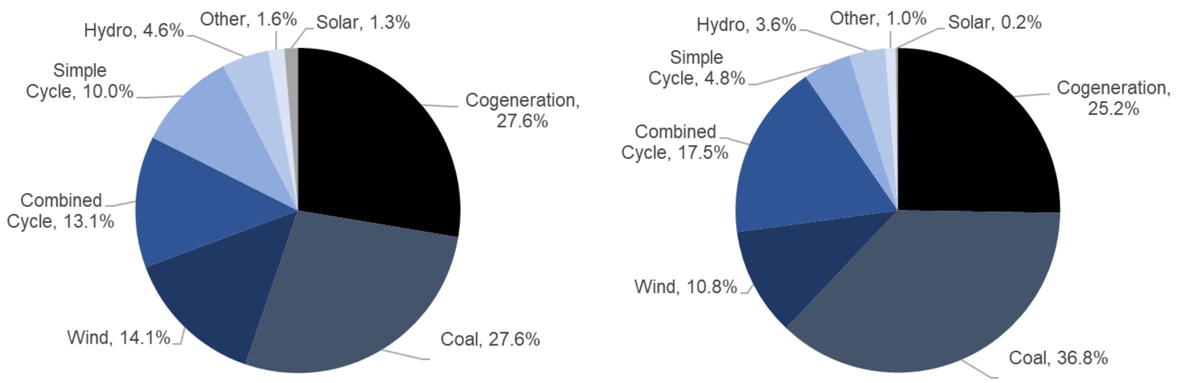
4 AESO, About the Grid, Available here: https://www.aeso.ca/grid/about-the-grid/, Last accessed: 23 September 2021. AESO, Exhibit 26054_X0004.01, 2021 Tariff Update Application Appendix B – 2021 Rate Calculations, Sheet "B-1 Rev Req", November 2020.

transmission expansion and enhancements through its transmission planning process. The AUC regulates the AESO, TFOs, and distribution facility owners in Alberta.

32. The AESO operates the competitive wholesale electricity market, which is a gross pool with hourly dispatch and a single hourly pool price.

33. As shown in Figure 2, the generation mix in Alberta is largely fossil fuel based, namely coal (approximately 28 percent of available capacity in March 2021), and gas and cogeneration (51 percent), with renewables constituting approximately 15 percent of available capacity as of March 2021.[5]

Figure 2: Electricity Generation in Alberta by Technology: Installed Available Generation Capacity in March 2021 (left) and Energy Production from April 2020 to March 2021 (right)



Source: See Attachment 5B; NERA Analysis of AESO Annual Market Statistics Report, Published March 19th 2021.

34. However, the system is in a transition, with all coal plant expected to retire by 2030. New transmission assets are expected to connect new gas generation, solar, and wind resources.[6]

2.1. Legislative framework in Alberta

35. We have been instructed by Norton Rose Fulbright Canada LLP, counsel to the AESO, to ensure our analysis reflects the following current legislative framework arising from

[5] AESO, Electricity in Alberta, 2019, Link: https://www.aeso.ca/aeso/electricity-in-alberta/.

[6] AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 1.

the Electric Utilities Act ("**EUA**") in the preparation of this Report, as detailed in our instruction letter:[7]

A. Rates under the tariff must be just, reasonable and not unduly discriminatory;

B. The ISO Bulk and Regional tariff can only be levied on load customers: distribution facility owners, customers who are industrial systems, persons who have made an arrangement, and exporters;

C. Any tariff levied by the ISO must seek to recover a defined annual revenue requirement, recover the costs reasonably attributable to each class of system access service provided by the ISO from such classes, and ensure that rates do not differ based upon the location of load on the transmission system; and

D. The ISO must plan a transmission system such that:

   i. Transmission of all anticipated in-merit electric energy can occur when all transmission facilities are in service 100 percent of the time; and

   ii. On an annual basis, transmission of all anticipated in-merit electric energy can occur when operating under abnormal operating conditions at least 95 percent of the time.

2.2. Our Understanding of the AESO's Approach to Transmission Planning

36. The AESO plans investment in the transmission system across six planning regions: Northwest, Northeast, Central, South, Calgary and Edmonton. The AESO further divides regions into subdivisions called "areas" that it uses in its transmission planning.[8] Figure 3 shows the six planning regions and 42 planning areas in Alberta.

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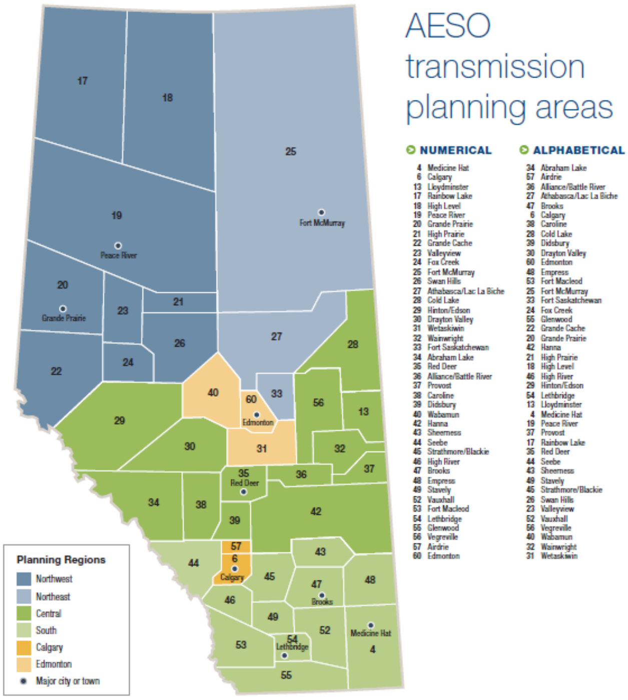
7 Norton Rose Fulbright, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, April 11, 2021. See Attachment 1A.

8 See for instance, in the AESO's discussion of its 2019 LTO load forecast in the 2020 Long Term Transmission Plan: "The tool models Alberta load across different granularities, i.e., POD, areas, regions, and the whole province". Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 12.

The AESO also uses planning areas in its planning as set out in Needs Identification Documents for new transmission investments. See for example: AESO, Amended Application of the Alberta Electric System Operator for Approval of the Needs Identification Document for the Provost to Edgerton and Nilrem to Vermilion Transmission System Reinforcement, 26 March 2018, Section 2.1.

Figure 3: AESO uses Six Regions and 42 Areas for Transmission Planning



Source: See Attachment 5C; AESO, Transmission Planning Areas.[9]

37. The load profile in Alberta is heavily concentrated in a small number of urban and industrial centers. For example, the Fort McMurray area in the Northeast planning region is rich in oil sands and is a large load center for industrial customers, comprising around a third of total load. The two largest cities, Calgary and Edmonton, account for approximately a third of total load. The remaining third of load is spread out across South, Central and Northwest planning regions and primarily results from industrial and agricultural demand.[10]

38. Historically, we understand that the bulk transmission system of 500 kV and 240 kV lines was developed to link the large urban centers with coal-fired generation in the Wabamun Lake region, located near, and to the west of, Edmonton. However, in more recent years, large oil sands development and load growth near Fort McMurray has driven transmission development. Growing renewable generation from wind and solar

9 AESO, Transmission Planning Areas, Available at https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf. Last accessed: 16 June 2021.

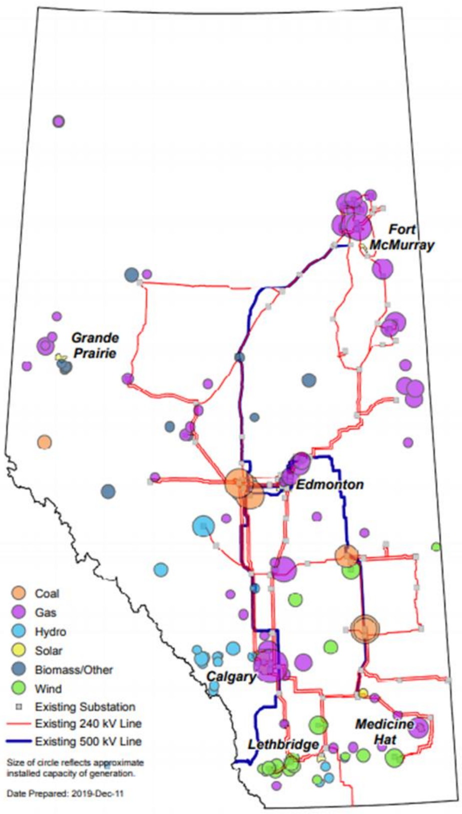
10 AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 19.

in the South and Central planning regions has also required transmission investment to accommodate the flow of in-merit energy around the province.

39. This pattern of historical transmission investment in Alberta, with relatively high voltages used to transmit power over large distances around the province, reflects the typical function of higher voltage lines seen across many jurisdictions, i.e. to move large volumes of electricity over long distances at a high voltage in order to keep losses to an economic level.

40. The map in Figure 4 shows the current location of transmission infrastructure and generators.

Figure 4: The Existing Location of Transmission Infrastructure and Generation in Alberta



Source: AESO, 2020 Long-term Transmission Plan, January 2020, p. 21

41. We understand that the Transmission Regulation (86/2007) obliges the AESO to prepare a 20-year Long Term Transmission Plan ("**LTP**") at least every two years. The

LTP must identify transmission facility projects needed within five years of the plan, and within five years of each update of the plan.[11]

42. The latest LTP, in 2020, uses two different timeframes to examine transmission needs:[12]

A. A "near-term assessment (five years)": In its near-term assessment, the AESO examines the regional planning needs in detail across the next five years. It constructs study cases to evaluate the transmission system under representative system-wide conditions, including local stress conditions and potential congestion; and

B. A "longer-term assessment" (covering a period greater than five years into the future): The AESO focuses on bulk, system-wide transmission needs, assessing outages at 240 kV or above, and monitoring assets at 138 kV and above, across a number of future scenarios.

43. The AESO constructs load forecasts to use in its transmission planning. It utilizes a model that forecasts hourly load more than 20 years into the future, and at different granularities (e.g. planning areas, regions, or the system). The AESO constructs its load forecast using load at three periods of time within the year to characterize different operating conditions for the transmission system:[13]

A. Winter peak defined by maximum load between Nov 1st and April 31st;

B. Summer peak defined by maximum load between May 1st and October 31st; and

C. Summer light defined by minimum load between May 1st and October 31st.

44. We understand that the AESO constructs its forecast profile of load across all hours of the year based on actual load in the past five years.[14] It also uses historical weather

11 Transmission Regulation, Alta Reg 86/2007. AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 1, p. 9, and p. 22.

12 AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 22. AESO, P1 – System Planning Report, Transmission Tariff Work Group, September 2019, Section 2.3.

13 AESO, Appendix B Load and Generation Forecast, p. 1. Link: https://www.aeso.ca/assets/Uploads/Appendix-B-AESO-Load-and-Generation-Forecast-CETO.pdf.

14 AESO, AESO 2021 Long-term Outlook, June 2021, p. 13.

profiles as well as other drivers of load such as gross domestic product, population, oil sands productionin its forecast of future load.[15]

45. To forecast generation in the long-run, the AESO forecasts the least-cost generation capacity that would need to be commissioned to meet forecasted demand. It considers drivers such as demand, fuel prices, and renewable generation profiles.[16]

46. The AESO then monitors lines that could require reinforcement in order to meet the planning standards as detailed in the Transmission Regulation. We understand that, for transmission planning purposes, the AESO approaches the need for transmission infrastructure on a case-by-case basis and is agnostic about the voltage of the assets. The AESO also takes a holistic view that does not distinguish planning solutions purely on the basis of line voltage, and may plan investments that provide joint solutions to current or future transmission needs.[17]

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[15] AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 12. AESO, AESO 2019 Long-term Outlook, Section 4.1.1, September 2019.

[16] AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 12.

[17] For example, the AESO identifies that the Provost to Edgerton and Nilrem to Vermilion ("**PENV**") Transmission System Reinforcement project is needed to both accommodate load growth and to provide options for future generation system access in the area. Source: AESO, Amended Application of the Alberta Electric System Operator for Approval of the Needs Identification Document for the Provost to Edgerton and Nilrem to Vermilion Transmission System Reinforcement, 26 March 2018.

3. Section 3 - The Current Rate Design

3.1. Overview of the Current Rate Design

47. The AESO is responsible for designing and setting the ISO Tariff which is paid by users who access the transmission system in Alberta. The AESO submits the ISO Tariff for approval by the AUC. Currently, the AESO follows an AUC approved embedded cost methodology (discussed further in Section 3.1) to set the ISO tariff.

48. The majority of the AESO's revenue requirement pertains to wires costs which are the annual payments it makes to TFOs to compensate TFOs for the investments they make in the transmission system (as planned by the AESO).

49. The AESO recovers the majority of wires costs, along with other costs, through the Demand Transmission Service (**"DTS"**) rate in the ISO tariff. The DTS rate is levied on load customers (i.e., distribution facility owners, customers who are industrial systems, and persons who have made an arrangement).[18]

50. The DTS rate is formed of five charges. The connection charge is the largest component of the DTS rate by revenue and recovers the wires costs as well as other operating costs of the AESO. Within the connection charge, wires costs are currently functionalized into those related to the bulk system, regional system, and those associated with POD.

51. In the following subsections, we describe how Bulk and Regional costs are currently recovered under the Current Rate Design.

3.1.1. Functionalization of costs

52. Under the Current Rate Design, the AESO functionalizes wires costs in the connection charge to be recovered from a bulk system charge, regional system charge, and POD charge. The current methodology is based on recommendations made by London Economics International LLC ("**LEI**") in 2014.

53. Under the Current Rate Design, the AESO functionalizes wires costs based on the net book value of the underlying assets delineated by voltage:

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[18] Norton Rose Fulbright LLP, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, 11 April 2021, Assumption B. See Attachment 1A.

A. The AESO uses the 2014 net book values of line and substation assets across four TFOs (AltaLink, ATCO Electric, ENMAX, and EPCOR).

B. It calculates the net book values of assets existing in 2014 at the end of the last calendar year at the time of setting the tariff. To calculate the net book values of assets, the AESO forecasts depreciation rates based on historical depreciation rates of each of the TFOs. It specifies separate depreciation rates for lines and substations. The AESO's forecast of deprecation holds depreciation constant at the last historically observed value for each of the TFOs.

C. It functionalizes assets existing in 2014 on the basis of voltage:

    i. Lines with voltages of 240kV or above are functionalized as bulk system lines (typically 500 kV and 240 kV lines).

    ii. Lines with voltages greater than 25kV but less than 240kV are functionalized as regional system lines (typically 144 kV, 138 kV, and 69 kV lines).

    iii. Lines are functionalized as POD lines if they serve a POD function for specific substations and/or end-use load, whereas lines serving generators are functionalized as bulk system lines.

D. Substations are functionalized on the basis of secondary voltage:

    i. Substations with secondary voltages greater than or equal to 240 kV are functionalized as bulk system substations.

    ii. Substations with secondary voltages between 138/144 kV and 69 kV (inclusively) are functionalized as regional system substations.

    iii. Substations with secondary voltages less than 25 kV are functionalized as POD system substations.

E. The AESO then aggregates the net book value of bulk, regional, and POD assets across TFOs, and calculates the ratio of the value of assets across the three systems.[19] It then functionalizes forecast capital maintenance estimated by TFOs in 2015 to the bulk, regional, and POD systems based on the ratio of the value of

19 The AESO adds an estimated lump sum value to the POD function to approximate the proportion of anticipated load connection project costs not covered by a contribution from the load market participant.

assets across the three systems. This gives the AESO the functionalization of assets commissioned in or before 2014 by value (in $), inclusive of capital maintenance.

F. Next the AESO functionalizes assets that it expects are commissioned after 2014 to the last calendar year at the time of setting the tariff. It forecasts the commissioning dates of each asset (line and substations). To functionalize line and substation assets, the AESO uses the same criteria as we set out in "C" and "D" above. It adds the total value of assets in the bulk, regional, and POD systems to the totals it calculates for 2014 assets plus capital maintenance as we set out in "E" above. The resulting total is the total capital costs in each system. The AESO calculates the "functionalization ratios" for bulk, regional, and POD capital costs based on the proportion of total capital costs constituted by bulk, regional, and POD system capital costs respectively.

G. The AESO then incorporates costs pertaining to operating and maintenance ("**O&M**") of assets. The AESO uses data on the O&M costs of the four TFOs functionalized by bulk, regional, and POD systems from 2010 to 2017. The AESO aggregates bulk, regional, and POD O&M costs and calculates the proportion of total O&M costs constituted by bulk, regional, and POD O&M costs respectively in each year across the TFOs. It then linearly extrapolates these proportions from the last three years of available data to the last calendar year at the time of setting the tariff. For example, to calculate the 2020 proportions, it extrapolates the trend from costs in 2015 to 2017 inclusive.

H. The AESO then aggregates the four TFOs' non-capital revenue requirements from previous years (2015 to 2017 inclusively), and extrapolates that multi-year data set to forecast capital and non-capital costs. It aggregates the revenue requirement and non-capital costs in each year across the four TFOs. The AESO then calculates the average proportion of total revenue requirement constituted by non-capital costs across the three years. The remaining proportion of costs constituting the revenue requirement are capital costs.

I. The AESO then calculates the total combined capital and O&M cost functionalization ratios. For each of the bulk, regional, and POD systems, it weights the functionalization ratios for capital costs, as calculated in "F", and non-capital costs, as calculated in "G", by the proportion of capital and non-capital costs in the revenue requirement, as calculated in "H." This gives it the total combined capital and O&M cost functionalization ratios for bulk, regional, and POD systems.

J. The AESO then performs a last adjustment whereby it splits its revenue requirement using the total combined capital and O&M cost functionalization ratios in "I". It then deducts costs associated with Regulated Generating Unit Connection Costs (payments to previously regulated generators) and adds costs associated with the "Competitive Process" to procure Fort McMurray West lines to bulk system. It then recalculates the final functionalization ratios based on the proportion of total remaining revenue constituted by bulk, regional, and POD revenue.

54. In the first step of determining the connection charge, the AESO splits total forecast wires costs in the tariff year across bulk, regional, and POD charges using the final functionalization ratios calculated in Paragraph 53.J above.

3.1.2. Classification of costs

55. The AESO then classifies the wires costs functionalized to the bulk system and regional system between demand and energy-based billing determinants. The AESO uses a similar methodology to classify both bulk and regional system wires costs, but uses different allocation factors and billing determinants. The AESO bases its methodology on recommendations made by LEI in 2014.[20]

56. The AESO uses a minimum system approach to classify costs between demand and energy-based billing determinants. The AESO follows LEI's recommendation of a minimum and optimal system approach that it justifies on the basis of the cost environment in 2014, and which defines the minimum and optimal systems on the basis of the costs of assets that are assumed to constitute each system.[21]

57. LEI states that "minimum system costs are driven by serving total load" whereas "costs incurred beyond the minimum system are driven by energy usage considerations."[22]

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[20] London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013.

[21] London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013.

[22] London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013, Lines 1568-1570.

58. LEI recommends that the AESO distinguishes minimum and optimized lines by conductor sizes. It identifies that:[23]

> *"TFOs are required to perform a conductor optimization study to determine the most economic conductor size, considering both capital costs and line losses, for all lines above 100 kV and longer than 10 km."*

59. Therefore, LEI states:[24]

> *"in order to approximate demand versus energy related costs, LEI has defined "minimum" and "optimal" conductor sizes as comparable lines that TFOs would consider, where the optimized line minimizes losses over the minimum line."*

60. LEI identifies the "two most commonly used" conductor sizes for each of 500 kV, 240 kV, and 138 kV lines in discussion with AESO staff. More specifically:

   A. For 500 kV lines, LEI determined that a 2x2156 Thousand Circular Mils ("**MCM**") Aluminum Conductor Steel-Reinforced cable ("**ACSR**") constitutes the minimum system conductor. LEI determined that a 3x1590 MCM ACSR constitutes the optimal system conductor.

   B. For 240 kV lines, LEI determined that a 2x795 MCM ACSR constitutes the minimum system conductor whereas a 2x1033 MCM ACSR constitutes the optimal system conductor.

   C. For 138 and 144 kV lines, LEI determined that a 266 MCM ACSR constitutes the minimum system conductor whereas a 477 MCM ACSR constitutes the optimal system conductor.

61. LEI examines the cost of each line conductor size in $ per km. It normalizes 138 kV line costs to single circuit lines and normalizes 240 and 500 kV costs to double circuit strung both sides. The costs of 240 kV and 138 kV conductors are sourced from the

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23 London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013, Lines 1582-1584.

24 London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013, Lines 1587-1590.

AESO cost benchmarking data file. The costs of 500 kV conductors are sourced from the California Independent System Operator ("**CAISO**") jurisdiction.

62. LEI recommends that the AESO distinguish minimum and optimized substations by transformer. Unlike its assumptions over conductor sizes, LEI does not distinguish substations used in the bulk and regional systems.

63. More specifically, LEI uses the cost of a POD "Standard Losses and Sound Level" transformer, which LEI assumes is representative of a transformer in the minimum system, and a POD "Lower No-Load Loss and Sound Level" transformer which LEI assumes is representative of the optimal system.[25] Unlike conductor sizes, LEI obtains cost information for the substation transformers from a single quote from a TFO in Alberta. It uses the quote for the POD substation to classify costs for the bulk and regional system substations.

64. Having obtained the costs of the assets that LEI assumes to constitute the minimum and optimal systems, the AESO classifies costs in the bulk and regional systems between demand and energy. The AESO undertakes the following steps to perform this classification:

A. For each line voltage and substation, the AESO calculates the proportion of the cost of the optimal system asset constituted by the cost of the minimum system asset. It names these proportions "allocation factors." The proportion of the cost of the optimal system asset constituted by the minimum system asset is the allocation factor of costs to demand (related to measures of peak consumption). The remaining proportion of costs are allocated to energy.

   i. For the bulk system, which comprises two types of lines delineated by voltage (240 kV and 500 kV), the AESO constructs a weighted average of the allocation factors of each asset, weighting by the total net book value of each type of asset in the last calendar year at the time of setting the tariff. There is only a single voltage of line considered for the regional system so no weighting of lines is required to calculate the regional allocation factor.

[25] London Economics International, Alberta Transmission System Cost Causation Study, 7 November 2013, Lines 1650-1660.

ii. After this step, the AESO has an allocation factor for lines in the bulk system, an allocation factor for lines in the regional system, and an allocation factor for substations which is common across the bulk and regional systems.

B. The AESO then constructs final allocation factors for the bulk system by constructing a weighted average of the allocation factor for lines in the bulk system and the allocation factor for substations. It weights by the total forecast net book value of each type of bulk system asset in the last calendar year at the time of setting the tariff using AltaLink and ATCO Electric asset data. The AESO performs a similar calculation for the regional system by constructing a weighted average of the allocation factor for lines in the regional system and the allocation factor for substations using AltaLink and ATCO Electric asset data. It weights by the total net book value of each type of regional system asset in the last calendar year at the time of setting the tariff. This step gives the AESO a final allocation factor between demand and energy for the bulk system, and likewise for the regional system.

C. Finally, the AESO applies the final allocation factors for the bulk and regional system, calculated in "B" above, to the relevant pool of costs functionalized into the bulk and regional system, calculated in Section 3.1.1 above, respectively.

65. This process classifies bulk system costs into those that are deemed demand-related and those that are deemed energy-related. Similarly, the process classifies regional system costs into those that are deemed demand-related and those that are deemed energy-related.

3.1.3. Billing determinants used to recover costs

66. The AESO recovers costs classified as demand-related using billing determinants that are demand-related or, in other words, related to measures of peak consumption. The billing determinant differs for bulk and regional system costs:

A. Bulk system demand-related costs are recovered from a charge levied on a measure of coincident peak in each month, referred to as "12CP." Each customer pays the 12CP charge based on their metered consumption during the time of coincident peak in each month in MW. The AESO determines coincident peak by calculating when metered demand at the point of delivery when averaged over a single 15-minute interval is the highest in each month. The AESO calculates metered demand as the sum of metered demand across all customers that pay the DTS or the Fort Nelson DTS. The 12CP charge is levied in $ per MW per month and does not vary across months of the calendar year of the tariff.

B. Regional system demand-related costs are recovered from a charge levied on a measure of non-coincident peak in each month referred to as "billing capacity." Each customer pays a billing capacity charge based on their billing capacity in each month in MW-month. The AESO determines billing capacity as the highest of:

i. the highest 15-minute metered demand in the settlement period;

ii. 90 percent of the highest metered demand in the 24-month period including and ending with the settlement period, but excluding any months during which commissioning occurs (energization or testing of the facility prior to normal operation); or

iii. 90 percent of the contract capacity or, when the settlement period contains a transaction under the Demand Opportunity Service rate, 100 percent of the contract capacity.

C. The billing capacity charge is levied in $ per MW per month and does not vary across months of the calendar year of the tariff.

67. The rationale for the choice of the current billing determinants to recover bulk and regional system costs has been discussed in previous General Tariff Applications.

A. The EUB has previously found that the bulk system is primarily sized to meet coincident system peak load:[26]

> *"The Board considers that system peaks are more important than load in every hour. The transmission system is planned for peak load. As acknowledged by the AESO under cross examination by Mr. Secord, peak load is the primary cause of maximum stress. The transmission system must be planned and built to withstand this stress. It follows that peak load is the cause and primary driver for*

[26] EUB Decision 2007-106, AESO, 2007 General Tariff Application, 21 December 2007, p. 24, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf.

bulk system costs Given that peak load is the primary driver for bulk system costs, the Board finds that it is the primary basis on which costs are to be allocated."

B. The Commission also states in AUC Decision 2014-242:[27]

"The Commission accepts that the system is primarily planned on the basis of system peak and that the 12 CP method is a reasonable method to collect bulk demand charges."

C. The use of 12CP is also supported by the Federal Energy Regulatory Commission ("**FERC**") and is used to varying degrees in other jurisdictions in North America. In FERC Order 888, the FERC states:[28]

"We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks."

D. In its direction of the AESO to utilize the non-coincident peak billing determinant with ratchet to recover regional system costs, in EUB Decision 2007-106, the EUB states:[29]

"The Board considers there to be considerably less diversity on the local system than the bulk system. The Board finds that the use of a ratchet at the local system level is a fair and efficient means to ensure recovery of those fixed costs caused by the relatively few, non-diverse customers present at any point on the local system."

E. The EUB has also recognized in previous rate proceedings that a portion of bulk and regional system wires costs are energy-related.[30]

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27 AUC Decision 2014-242, August 21, 2014, p. 27, para. 129.

28 FERC Order 888, Docket Nos RM95-8-000 and RM94-7-001, 24 April 1996, p. 296.

29 EUB Decision 2007-106, AESO, 2007 General Tariff Application, 21 December 2007, p. 35, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf.

30 See for instance: EUB Decision 2007-106, AESO, 2007 General Tariff Application, 21 December 2007, p. 32. Available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf.

68. The AESO recovers both bulk and regional system energy-related costs through a flat charge in $ per MWh levied on each customer's total metered energy consumption each year.

69. The AESO determines the value of charges to levy by dividing the total costs to be recovered from the billing determinant by its forecast total billing determinant for the upcoming calendar year. We illustrate this calculation for charges in 2021 in Table 2 below.

Table 2: Bulk and Regional System Charges Under Current Rate Design 2021

Charge	Cost	Billing Determinant	Rate
Bulk System Charge			
Coincident Demand	$1,015.5m	91,617 MW-months	$11,085 per MW per month
Energy Charge	$71.2m	58,399 GWh	$1.22 per MWh
Regional System Charge			
Non- Coincident Demand	$462.8m	159,954 MW-months	$2,893 per MW per month
Energy Charge	$54.0m	58,399 GWh	$0.93 per MWh

Notes: Includes non-wires costs functionalized to bulk and regional systems. Source: AESO, Appendix-B-2021-Rate Calculations, X0004.01.

3.2. Recent Trends in Charges

70. There has been a large rise in transmission investment in Alberta, particularly in the bulk system, in the past ten years. Significant projects completed in the past ten years include:[31]

A. North-South Transmission Reinforcement: two HDVC 500 kV double circuit transmission lines connecting North and South planning areas;

B. Fort McMurray Transmission Project: a 500 kV single circuit transmission line connecting the Wabamun Lake area and Fort McMurray;

C. Heartland Transmission Development: a 500 kV double circuit transmission line to strengthen supply to Edmonton-area large industrial loads and the Northeast; and

[31] AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 20.

D. Southern Alberta Transmission Reinforcement: 240 kV transmission system reinforcements in southern Alberta to integrate renewable generation.

71. 12CP charges have risen significantly since 2014, as we illustrate in the bottom panel of Figure 5 below. The rise in 12CP charges has been driven by the need to recover costs associated with an increase in bulk transmission system investment in Alberta since 2014. Moreover, while investment in the bulk transmission system has increased significantly, growth in coincident peak demand has been modest, resulting in increasing costs needing to be recovered from roughly the same billing determinant over the same period.

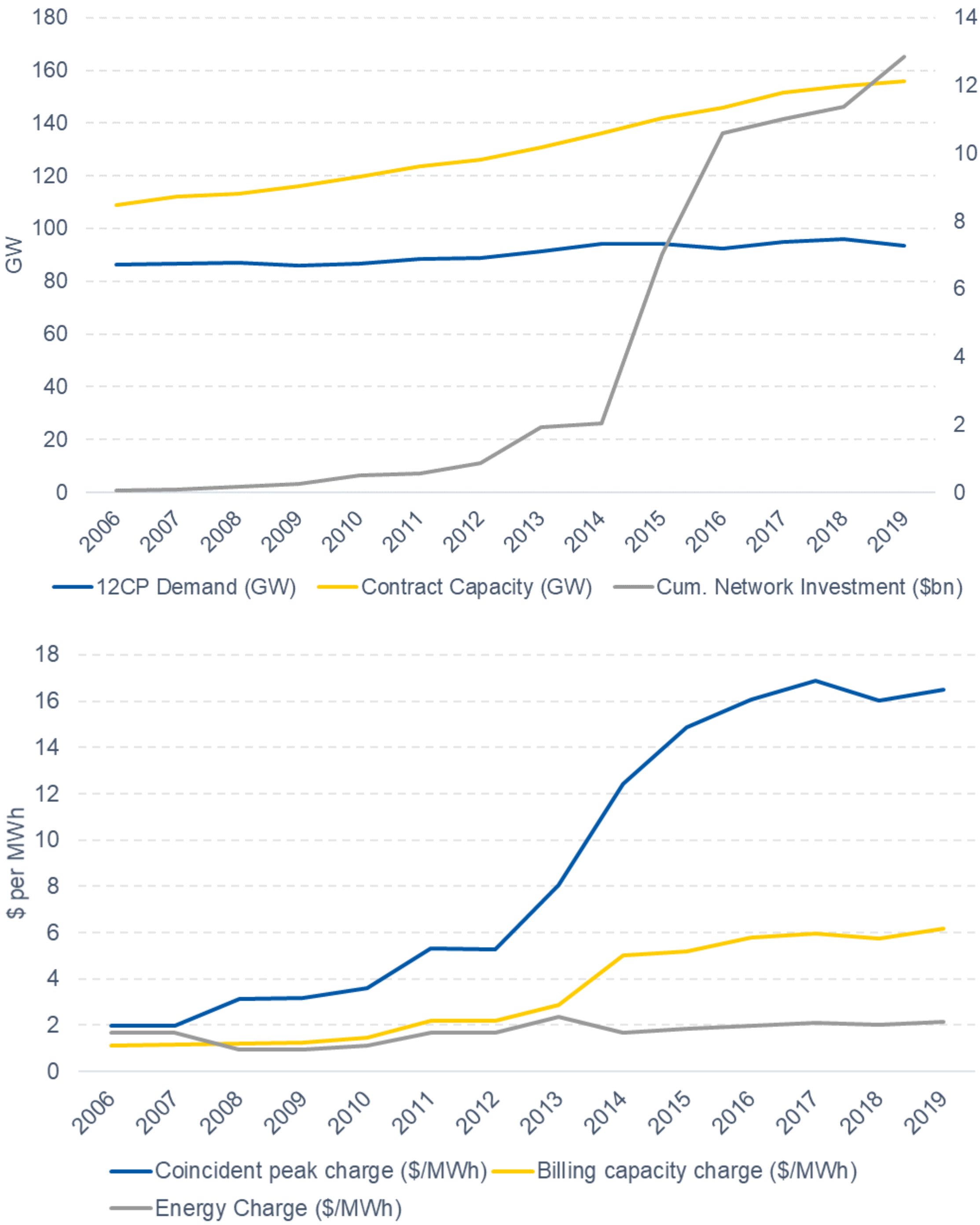
72. We understand that customers have responded to the price signal sent by the increasing 12CP charge by avoiding consumption at times of 12CP.[32] This has reduced the charging base for the 12CP charge, exacerbating the increase in the 12CP charge required to recover bulk system transmission costs.

73. By contrast, contract capacity has risen steadily since 2007, resulting in a smaller rise in billing capacity charges relative to 12CP charges.

74. The graph on the top of Figure 5 shows the significant increase in network investment since 2007—particularly in 2015 and 2016. Total Coincident Metered Demand has grown modestly while contract capacity has increased relatively more over the period. The graph on the bottom of Figure 5 shows the effect of load growth and investment on tariff charges between 2007 and 2019.

[32] AUC, Distribution System Inquiry 24116-D01-2021, 19 February 2021, para 325. AESO, Bulk and Regional Tariff Design Stakeholder Engagement Session 4, 10 December 2020, p. 49.

Figure 5: Demand, Investment, and Tariffs, 2006-2019



Note: 12CP and Billing Capacity charges converted to $ per MWh terms by dividing total revenue from each charge by total annual DTS energy consumption. 12CP and Billing Capacity charges are actually levied on a $ per MW-month basis. Source: See Attachment 5D; NERA Analysis of AESO, Bulk and Regional Tariff Design Stakeholder Engagement 4, 10 December 2020, slides 47-48, available at: https://www.aeso.ca/stakeholder-engagement/rules-standards-and-tariff/bulk-and-regional-tariff-design/.

3.3. Potential Drivers of Change in Transmission Costs in Alberta

3.3.1. The AESO plans transmission investments to accommodate flows of in-merit energy, not solely to accommodate demand growth

75. The recent rise in transmission investment, and by extension the AESO's revenue requirement, that we illustrate in Section 3.2 has been driven by transmission planned not only to accommodate demand growth, but to accommodate flows of in-merit energy.

76. Alberta's generation fleet is undergoing significant change. We understand that coal plants will be converted to gas plants by 2022 or otherwise retired by 2029.[33] The majority of existing coal plants are located in the Edmonton planning region (see Table 3 below).

Table 3: Coal Generation Capacity Across Planning Regions in Alberta (MW)

Planning Region	2018	2024 (F)	Change
Northwest	144	0	-144
Northeast	0	0	0
Edmonton	4,100	4,100	0
Central	689	540	-149
South	790	790	0
Calgary	0	0	0

Note: 2024 as forecast in the LTP. Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020.

77. Meanwhile, renewable generation capacity has grown in recent years, and is expected to grow in the future. Wind and solar renewable generation potential are the highest in South and Central planning regions in Alberta, as shown in the left-hand side and right-hand side of Figure 6 below, respectively. In its 2020 LTP, the AESO forecast significant growth in wind and solar generation capacity by 2024 in the South planning region (see Table 4).

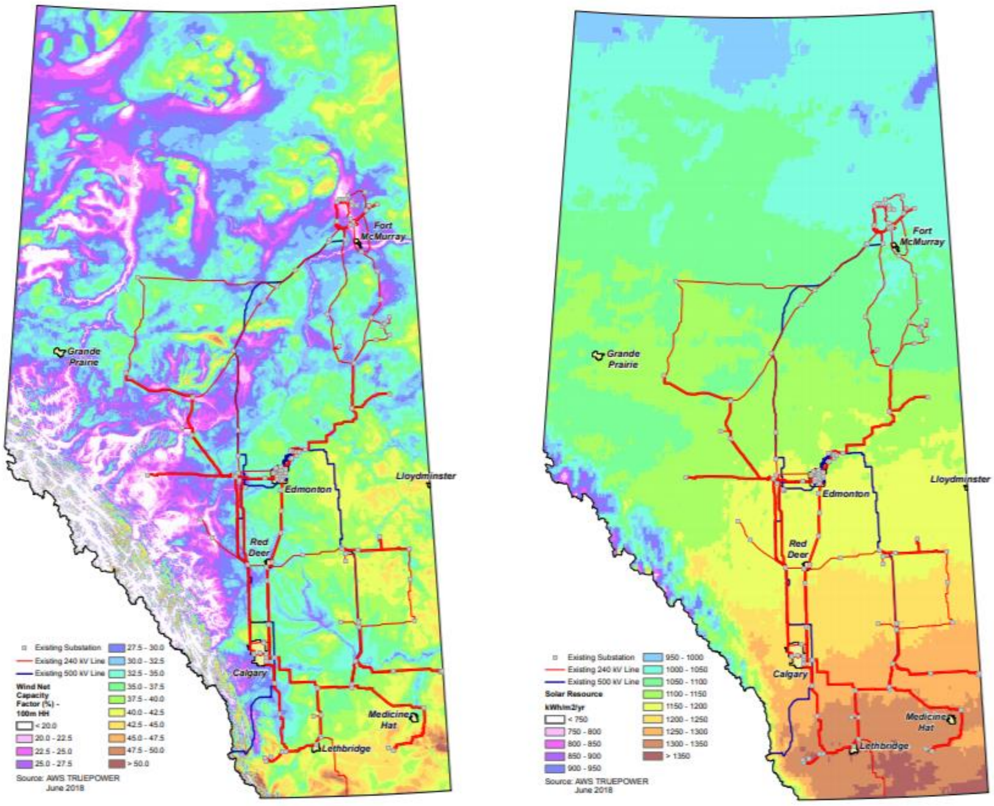
33 AESO, AESO 2021 Long-term Outlook, June 2021, p. 24.

Table 4: Forecast Change in Generation Capacity Between 2018 and 2024 Across Planning Regions in Alberta (MW)

	Northwest	Northeast	Edmonton	Central	South	Calgary
Change to Total of Coal-fired and Converted Coal-to-gas Capacity	-144	0	0	-149	0	0
Change to Wind and Solar Capacity	0	0	0	248	1,327	0
Total Change in Generation Capacity	-36	271	0	241	1,373	46

Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020.

Figure 6: Wind and Solar Potential in Alberta



Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020.

78. Hence, while the expansion of renewable generation capacity is likely to predominantly occur in the South and Central planning regions, coal plant retirements will reduce capacity in the Edmonton region. These changes in generation capacity will alter the locational pattern of generation relative to load. This means that the locational pattern of flows of in-merit energy will also change across the province.

79. The changing flows of energy require incremental investment in the transmission network in order to accommodate the flow of in-merit energy and meet the planning standards required by legislation. The AESO makes clear in its System Planning Report that it has already planned transmission investments to accommodate expected changes to the pattern of flows of in-merit energy across the province. [34]

80. The AESO is also planning to integrate renewable generation in the future and facilitate the flow of in-merit energy to load across the province. For example, in its 2020 LTP, the AESO identifies the following potential transmission developments may be required in the near term (amongst others):[35]

A. In the Central planning region, a "*240 kV transmission line to increase transfer-out capability to integrate additional generation*"; and

B. In the South planning region, a "*500 kV Chapel Rock substation, 240 kV transmission line and a voltage support device to increase transfer-out capability to integrate additional generation and help restore the Alberta—British Columbia (B.C.) intertie.*"

81. Therefore, future transmission costs, as well as the recent rise in transmission costs that we identify in Section 3.2, constitute both investments that the AESO has planned to accommodate demand growth, as well as investments that it has planned to accommodate flows of in-merit energy. The AESO recognizes that not all transmission investments are required in order to serve demand, and justifies investments on whether they are principally required to serve "load" or "generation" or both.[36]

3.3.2. Flows on transmission lines also suggest that changes in demand are not the sole driver of transmission investment

82. To examine the drivers of transmission investment further, we also examine historical power flows on bulk transmission lines and their incidence with times of coincident peak. We find times of high utilization of lines occur at times other than coincident

[34] See for instance the Southern Alberta Transmission Reinforcement ("**SATR**") which is a 240 kV transmission reinforcement to "integrate renewables generation". Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 20. Further projects are listed: AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 6.

[35] AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 6.

[36] AESO, AESO 2020 Long-term Transmission Plan, January 2020.

peak supporting our qualitative analysis (see Section 3.3.1) that the AESO also plans investments to accommodate flows of in-merit energy, not solely to accommodate demand.

83. Consistent with the drivers of recent and planned transmission investments described above, transmission investment is required to meet the Transmission Regulation when the existing transmission network is unable to accommodate flows resulting from changes in peak demand or the pattern of in-merit energy. In its transmission planning, we understand that the AESO identifies areas of the network which require investment to accommodate flows of in-merit energy, and uses forecasts to study lines that have flows during some hours close to their line capacity.[37]

84. Therefore, to further examine the drivers of transmission investment alongside our qualitative analysis above, we constructed a measure of incidences of high flows on bulk transmission lines using SCADA data for real power flows. We examined hourly flows on lines in the bulk system in Alberta in 2017 to 2020 (inclusive). Our measure sums flows, in each hour and in MW, across all lines experiencing flows in the hour greater than or equal to 90 percent of their maximum hourly flow for the year.

85. We can then compare our measure of high flows on bulk transmission lines to potential drivers of bulk transmission investment. For instance, we can compare incidences of high flows to incidences of monthly coincident peak to assess the extent to which coincident peak coincides with high flows on lines, which may indicate the need for transmission investment.

86. Our analysis serves as a cross-check on our qualitative assessment of trends in demand and transmission investment in the province, as we discuss in Section 3.3.1. If peak demand is the predominant driver of bulk system costs, we would expect to see incidences of high flows on transmission lines occurring predominantly at times of system coincident peak. However, if we observe multiple incidences where high flows on lines occurs at times other than coincident peak, then our analysis would suggest other determinants are important drivers of transmission investment in the bulk system.

37 AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 61.

87. Our measure of high flows on lines does not consider the capacity of each bulk line, due to data limitations.[38] However, we expect that incidences of high flows on lines relative to peak flows across lines of the system indicate the need for transmission capacity, which must be large enough to accommodate peaks in flows across lines.

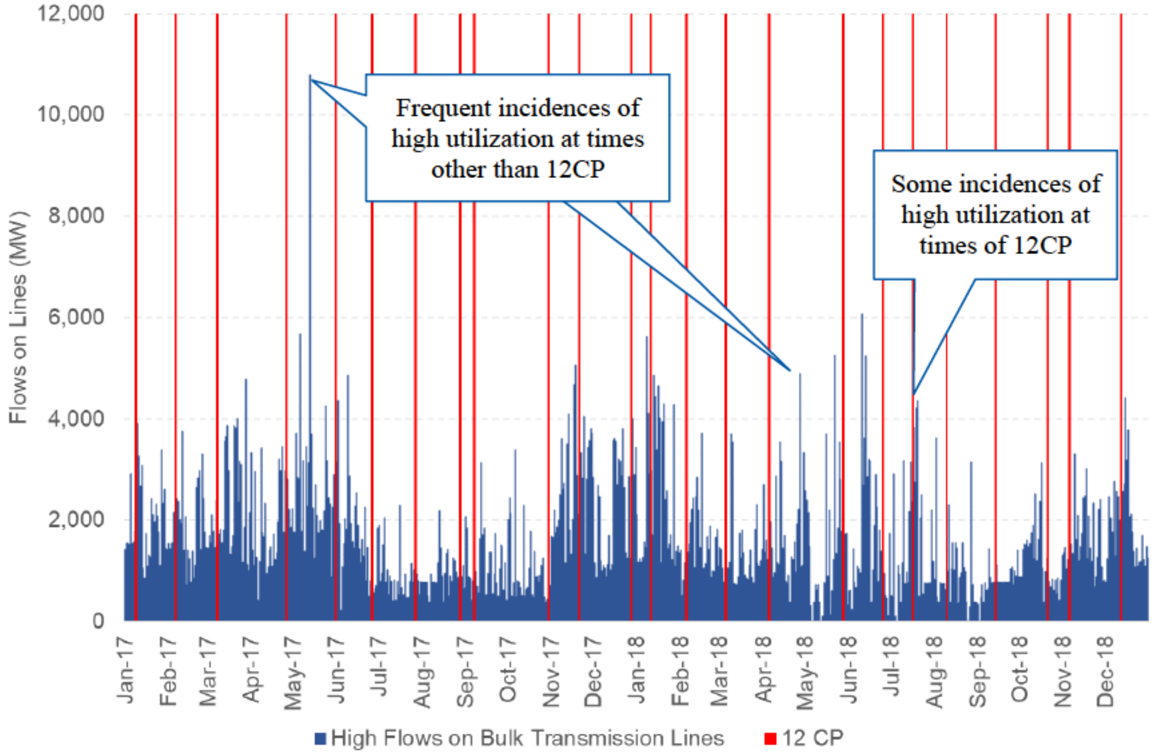
88. We compare our measure of high flows on lines to hours when 12CP occurs in Figure 7 below. The vertical orange lines indicate the 12CP hours, while the blue line measures the total flows across all bulk lines which are (in each hour) experiencing flows within 10 percent of the peak flows they experience throughout the year.

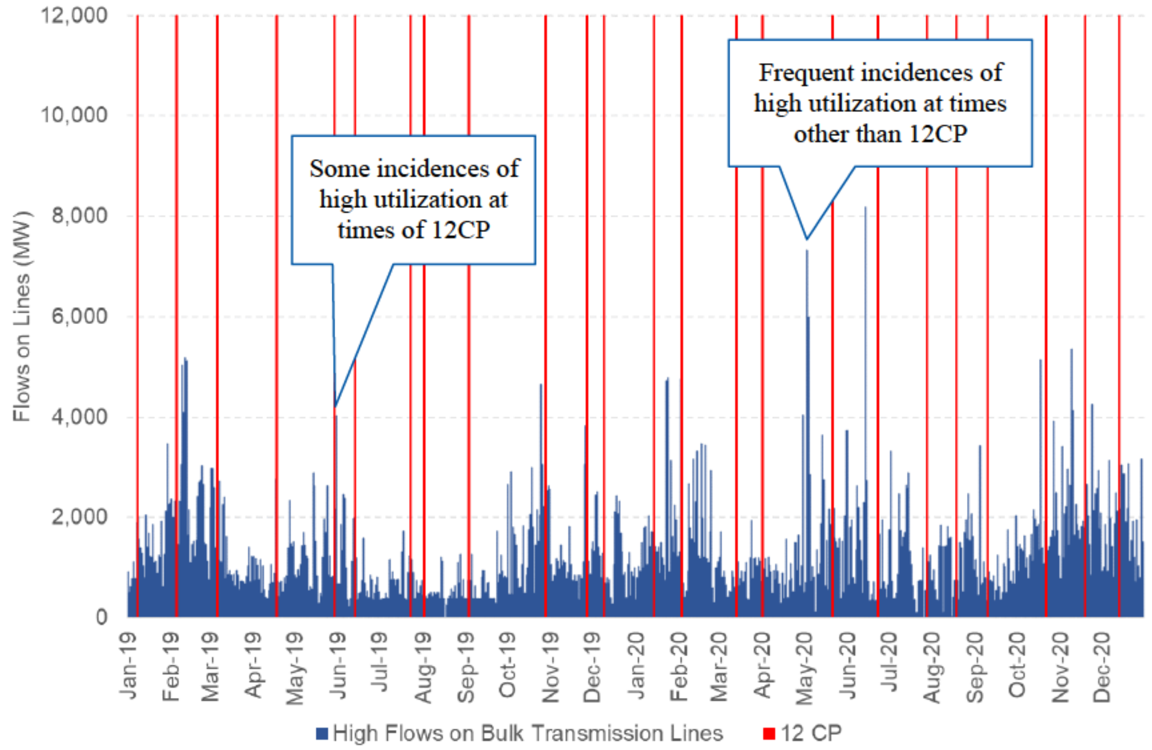
89. As Figure 7 shows, we observe that some hours of high flows on lines coincide with hours of 12CP, suggesting coincident peak demand may drive the need for some bulk transmission lines.

90. However, we also observe that hours of high flows on lines across the bulk transmission system frequently occur at times other than coincident peak. Given that high flows on transmission lines are an indicator of the need for transmission investment to accommodate peak flows, our analysis suggests other determinants are important drivers of transmission investment in the bulk system.

[38] Specifically, in order to account for the capacity of bulk lines, we would need to map the line capacities to the flows on lines as detailed in the SCADA data. We did not have a complete mapping available to perform this. The capacity of such lines would also vary over time, e.g. because of investments, or within year due to weather conditions affecting thermal limits on overhead lines resulting in imprecise estimation even if the data was available.

Figure 7: Hours of High Flows on Bulk Transmission Lines and 12CP (2017-20)





Source: See Attachment 5E; NERA Analysis of SCADA line flow data provided by the AESO.

91. This quantitative analysis supports our qualitative assessment, and suggests that the Current Rate Design, which recovers the large majority of costs from a 12CP charge, may no longer reflect the factors driving the need for transmission capacity on the bulk system. In other words, the tariff recovers an amount of transmission costs from a charge levied on peak demand which is disproportionate to the likelihood that the flows on transmission lines is highest at those times, suggesting the tariff could be altered to better reflect the drivers of investment in transmission infrastructure. Instead, it may overstate the transmission costs associated with serving coincident peaks in demand.

3.3.3. The Current Rate Design could better reflect the drivers of transmission investments by distinguishing costs associated with accommodating flows of in-merit energy

92. The Current Rate Design classifies 93.4 percent of bulk system wires costs to be recovered from a charge levied on 12CP.[39] The 12CP charge has risen significantly relative to 2007, as we discuss in Section 3.2, with rising investments in the bulk system. However, the classification of bulk system costs between 12CP and energy charges in the Current Rate Design has not changed significantly.[40]

93. The recent rise in transmission costs that needs to be recovered through the Current Rate Design has highlighted shortcomings in its design, and demonstrated it could be better aligned to the drivers of transmission investment in Alberta.

94. The AESO has continued to plan, and receive approval for, investments to accommodate flows of in-merit energy in the province, associated with the changing locational pattern of in-merit generation relative to demand. However, the Current Rate Design recovers the majority of bulk-system costs through a charge levied on 12CP, irrespective of the driver of those investments.

95. Consequently, as bulk transmission costs have significantly increased in recent years without similar growth in coincident peak demand, the 12CP charge has risen substantially. The rise in 12CP charges experienced in recent years due to rising

[39] AESO, Exhibit 26054_X0004.01, Appendix B – 2021 Rate Calculations, Sheet "B-5 DTS Classification".

[40] The choice of assets that constitute the minimum and optimal system has not changed since 2014. There have been small changes in the weights given to different types of asset (the two bulk conductors, and substations) in the calculation of allocation factors.

transmission investment does not reflect all of the drivers of those costs, and most notably it does not reflect investments required to accommodate flows of in-merit energy.

96. Therefore, the 12CP charge sends inefficient price signals to customers because it overstates the costs associated with using the grid at peak time, as we discuss further in Section 5 below. This is because investments to accommodate flows of in-merit energy may occur at times other than coincident peak, but the tariff recovers those costs through a charge on 12CP. For example, transmission investments required to accommodate the flow of in-merit energy may be driven by times of high renewable generation output (e.g. windy hours) rather than times of coincident peak. We demonstrate that high flows on bulk transmission lines occur at times other than coincident peak in our analysis in Section 3.3.2. Recovering costs of investments associated with accommodating flows of in-merit energy through a charge levied on 12CP does not meet the principle of cost causation.

97. Consequently, customers have responded to the *inefficient* price signal sent by the current 12CP charge by avoiding consumption at times of 12CP, leading to inefficient self-supply or consumption decisions.[41] This behaviour in response to the inefficient price signal sent under the Current Rate Design has reduced the charging base for the 12CP charge, further exacerbating the increase in the 12CP charge required to recover bulk system transmission costs.

[41] AUC, Distribution System Inquiry 24116-D01-2021, 19 February 2021, para 325. AESO, Bulk and Regional Tariff Design Stakeholder Engagement Session 4, 10 December 2020, p. 49.

4. Section 4 - Our Evaluation Criteria

98. In evaluating alternative approaches to the tariff design, we use the well-known regulatory principles developed by James Bonbright.[42] These regulatory principles are widely respected and continue to be used in rate design across North America to assess desirable rate structures. They include:

A. Recovery of the total revenue requirement;

B. Provision of appropriate price signals that reflect the costs of providing the service;

C. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies; and

D. Stability and predictability of rates and revenue.

99. The AUC, and its predecessor the Energy and Utilities Board ("**EUB**"), have also relied upon similar principles as they relate to transmission tariff design since at least 2005.[43]

100. In 2007, the EUB reiterated these principles and added a fifth criterion with which to evaluate rate design: practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.[44]

101. In its 2010 Decision regarding the ISO Tariff, the AUC stated:

> *"To conclude, with regard to the rate design principles discussed above, the Board considers that cost causation must be afforded the most weight in attempting to balance these sometimes competing principles when evaluating a proposed rate design. That is, in reviewing a proposed rate design, the Board finds that it is critical that the rate design proposed ensures that a customer that causes a cost must be prepared to pay that cost. The principle of rate shock, which can conflict with this cost causation principle, must take a secondary consideration to cost causation in arriving at an*

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[42] Bonbright, James. *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 291.

[43] EUB Decision 2005-096, Alberta Electric System Operator (AESO), 2005/2006 General Tariff Application, 28 August 2005, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2005/2005-096.pdf.

[44] EUB Decision 2007-106, AESO, 2007 General Tariff Application, 21 December 2007, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf.

> *appropriate rate design. The balance of the criteria can usually be seen as complimentary to cost causation. On balance, if rates reflect causation, barring unusual regulatory events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism.”* [45]

102. The AUC continued to uphold these five principles in its most recent decision in 2019, regarding the AESO’s 2018 Tariff application.[46] The AESO also relies upon Bonbright principles in its regular presentations to stakeholders.[47]

103. In establishing evaluation criteria to assess potential tariff designs, we follow the AUC and the AESO in adopting well-accepted Bonbright principles. However, we consider some principles are more important considerations than others in the rate design. In particular:

    A. **Cost causation:** Following AUC precedent, the main criterion we apply in our evaluation of alternative tariff design options is that the tariff design provides appropriate price signals that reflect the costs of service associated with different patterns of usage. To promote economically efficient consumption decisions, the tariff should be structured to reflect the long-run link between how and when customers use the transmission system and the costs of providing that transmission.[48] For instance, customers drawing different amounts of power from the grid, having different amounts of contracted capacity, or using the grid at different times, may all impose different transmission costs.

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[45] AUC Decision 2010-606, AESO, 2010 ISO Tariff, 22 December 2010, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010-606.pdf.

[46] AUC Decision 22942-D02-2019, AESO, 2018 Independent System Operator Tariff, 22 September 2019, available at https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2019/22942-D02-2019.pdf.

[47] For example, see AESO, Bulk and Regional Tariff Design Stakeholder Engagement 5, 25 March 2021, slide 17, available at https://www.aeso.ca/assets/Uploads/Presentation-Session-5-March-30.pdf.

[48] Economists refer to a concept named “allocative efficiency” which describes when the costs of providing a service are aligned with consumers’ value of a service and therefore the combination of production and consumption represents a desirable outcome for society. To achieve allocative efficiency in the context of transmission use, users of the transmission system rely on the price signal sent by the transmission charge to reflect the long-run cost of providing transmission. An inefficient price signal, in the context of transmission charges, arises when the transmission charge does not reflect the long-run cost of providing a service, and therefore leads to too high or too low usage of the transmission system, resulting in a sub-optimal outcome for society. See for instance: Harvey Leibenstein. Allocative Efficiency vs. “X-Efficiency”, June 1966, The American Economic Review, Vol. 56 (3), p. 392-415.

B. **Recovery of the revenue requirement:** We recognize that transmission charges should be set under any tariff design methodology such that the AESO expects to recover its revenue requirement each year. We also understand that the regulatory framework in Alberta provides the AESO with an opportunity to correct differences between its actual revenue and revenue requirement in the calculation of tariffs in subsequent years. Therefore, we assess that this criterion has limited use in evaluating different tariff methodologies in circumstances where the utility has a right to recover costs in future years.

C. **Fairness, objectivity, and equity**: We assess that if a rate design sends price signals that reflect the costs of providing transmission, thereby meeting the cost causation criterion, then that rate design is likely to be both fair and objective. A tariff that reflects the costs of providing transmission would also be equitable because differences in tariff costs across customers would reflect the costs caused by those users. Therefore, we assess that this criterion, while important, is largely met through meeting the cost causation criterion.

D. **Stability and Predictability:** We consider it important for the tariff to be stable and predictable, in the sense that we would not recommend a tariff design that can change materially from year-to-year in conditions where transmission usage patterns and transmission costs are not similarly variable across years. However, tariff stability should not be prioritized over ensuring the tariff remains cost reflective.

E. **Practicality:** We understand that any rate design needs to be administered by the AESO. Therefore, ease and practicality of implementation is an important consideration in our evaluation of alternative tariff methodologies. We also understand that customers need to understand the structure of the tariff to be able to predict their transmission costs, and how changes in their consumption behaviour will result in them paying different charges. This is necessary both to adhere to the principle of fairness (discussed above), but also to ensure customers can respond to the efficient price signals sent in the tariff. Therefore, we consider the practicality of the tariff from both the view of the AESO and customers in our evaluation of alternative tariff methodologies.

104. Across all of the Bonbright principles, we consider that the cost causation principle is the most important for evaluating our Recommended Rate Design. A rate design that meets the principle of cost causation would likely meet principles of fairness, objectivity, and equity.

5. Section 5 - Marginal vs. Embedded Cost Approaches to Tariff Design

105. Tariff design methodologies for regulated utility and infrastructure assets can typically be characterized as following one of two broad types of methodology: a "marginal cost" methodology or an "embedded cost" methodology. In this section, we describe these two broad approaches to tariff design and describe the applicability of each in the context of the AESO's tariff for the recovery of bulk and regional costs.

5.1. The Theoretical Advantages of a Marginal Cost Approach

106. The practical application of rate design in North America and elsewhere sometimes uses a "marginal cost approach" as a potential solution to the problem of historical costs exceeding the forward-looking costs associated with future changes in demand for electricity. This approach sets tariffs based on an estimate of how a change in demand from a customer will affect the future costs of a utility.[49]

107. A theoretical advantage of a marginal cost approach is the ability to send an efficient price signal that reflects the costs imposed by incremental changes in demand on the system. This price signal should be sent through a charge which is "avoidable" or varies with customers' consumption behaviour. As it applies to transmission rate design, in theory marginal cost-based prices promote efficiency by allowing customers to trade-off the benefits they derive from consuming electricity drawn from the transmission system (which may include the value derived from consumption or the costs of alternative self-generation options) against the transmission costs their consumption creates (as well as other costs such as the wholesale market price).

108. The concept of marginal cost-based pricing is discussed in the context of distribution network rate design in the AUC's recent Distribution System Inquiry:[50]

> *"distribution rates should contain a variable component to provide a forward-looking price signal to customers to manage their use of distribution system services that will affect the future costs of the*

[49] National Association of Regulatory Utility Commissioners ("**NARUC**"), Electric Utility Cost Allocation Manual, January 1992, p. 12-14.

[50] AUC, Distribution System Inquiry 24116-D01-2021, February 19 2021, para 311.

network. This forward-looking component is based on variable charges (volumetric charges or avoidable demand, such as CP charges)"

109. There are a number of methods to estimate the forward-looking marginal-cost component cost of transmission, including the projected embedded approach, the system planning approach, the regression approach, and load flow modeling:

A. The projected embedded approach relies on historical data and a simple projection of past costs and practices into the future to estimate the marginal cost associated with changes in demand.[51]

B. The system planning approach is fully forward looking, relying on a base case of expected load growth and transmission investments, and an incremental case for the same period.[52]

C. The regression method uses a statistical procedure (i.e. a regression) to quantify the relationship between billing determinants and transmission investment, from which a marginal cost estimate can be derived.[53]

D. Load flow modeling builds a representation of the existing transmission infrastructure within a technical model characterizing how power flows around the system and uses it to quantify how changes in demand and generation affect future investment requirements.[54]

110. A marginal cost-based methodology could send multiple price signals reflecting the marginal cost of different types of consumption behavior. For instance, a tariff could include separate components that reflect the costs incurred to accommodate additional units of coincident peak demand, non-coincident peak demand, or an additional unit of energy demand.

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[51] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 129-132.

[52] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 132-134.

[53] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 129-132.

[54] Load flow modelling is used in other jurisdictions. See for instance: Connection and Use of System Code, Section 14 in Great Britain.

111. However, setting prices equal to an estimate of marginal cost will not usually (except by coincidence) generate enough revenue to recover the revenue requirement.[55] The difference between the revenue earned under marginal cost prices and the revenue requirement is often called the "residual".

112. Consequently, in order to recover the revenue requirement efficiently, the marginal cost methodology prescribes that the residual should be recovered in a way that avoids distorting the consumption decisions that customers would take in response to the efficient price signals conveyed by marginal cost component of the tariff alone. As explained in the AUC's Distribution System Inquiry:[56]

> *"Whenever an attempt is made to recover embedded or sunk costs (also referred to as "residual costs" in the quote above) through charges that customers can avoid (such as volumetric charges or CP demand charges), improper incentives (i.e., incentives contrary to the public interest in the least cost provisioning of electricity) arise to invest in self-supply, resulting in (i) under-recovery of fixed system costs; (ii) cost shifting to other customers; and (iii) uneconomic bypass."*

113. In light of the above, there are three common methods to recover residual costs in a marginal cost-based tariff:

A. Ramsey pricing recovers residual costs based on the relative elasticities of demand for different classes of customers.[57] Those classes with the highest price sensitivity will be charged the price closest to marginal cost (hence recovering less residual cost) while those that are least likely to respond to price will be charged the price that deviates the most from marginal costs (reflecting more residual costs).[58]

B. However, recognizing that it can be challenging to identify the price elasticity of demand for all customers, the tariff could recover residual costs based on a charge

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55 NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 147.

56 AUC, Distribution System Inquiry 24116-D01-2021, February 19 2021, para 310.

57 The elasticity of demand describes the extent to which customers can and are willing to change their behavior to avoid the charge. A higher elasticity of demand refers to a customer that is more willing to change their behavior to avoid the charge.

58 NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 155-160.

levied on a billing determinant which is least likely to distort customer behaviour (and the price signal sent by the marginal cost component of the charge).[59]

C. Another method to recoup residual costs is to apply a proportional mark-up to the marginal-cost component of the charge.[60] This approach is relatively simple to administer, and can result in a similar outcome to Ramsey pricing if customer classes that impose the highest marginal costs also have the least price elastic demand. However, it distorts the marginal cost price signal, and so undermines the economic efficiency properties of marginal cost pricing.

114. The choice of methodology to recover residual costs should also consider the equity of the tariff design.[61] For instance, levying a fixed charge per customer may disproportionately impact smaller customers relative to larger ones.

5.2. Challenges of Applying a Marginal Cost Approach to Set the Bulk and Regional Tariff

5.2.1. The marginal cost of transmission varies by location, which cannot be reflected in the tariff

115. While the marginal cost approach is theoretically appealing as a means of encouraging efficient consumption and self-supply decisions, the current legislative framework in Alberta significantly limits the efficiency benefits of the approach.

116. The efficiency of a marginal cost approach to set a regulated utility tariff that will apply to a wide set of customers (e.g. across a whole “class” of ratepayers) relies on the assumption that all such customers’ consumption decisions would have a similar impact on the utility’s costs. For instance, in a distribution system, it is reasonable to assume that changes in customers’ consumption decisions (or growth in the number of customers) will have a similar effect on the distribution utility’s costs because the majority of residential and small commercial electricity customers have similar sized connections and are served with similar types of infrastructure.

[59] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 162.

[60] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 160-162.

[61] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 164-165.

117. In a transmission system, by contrast, it is not safe to assume that changes in all customers' demands have the same impact on the transmission system's costs:

A. New demand connecting to the system in a location that is close to new generation may help the AESO to avoid the need to reinforce the transmission system to evacuate power from the new generation facility. As such, the marginal cost of accommodating this particular change in demand would be negative.

B. On the other hand, additional energy consumption in locations near generators due for retirement, or in locations where demand is already high relative to the generation located nearby, may increase transmission costs. The marginal cost of accommodating such changes in demand would be positive.

118. In practice, the investments that the AESO identifies in the 2020 LTP suggest that changes in customers' consumption decisions in different locations of the network could be associated with different amounts of avoidable costs. For instance, while the AESO is currently only planning a single investment in the Northeast planning region to mitigate voltage criteria violations driven by *load*, it is planning multiple new single-circuit lines to alleviate *load* thermal constraints in the Northwest, two new bulk line circuits in the Central planning region to alleviate *generation* thermal constraints, and a new regional line in the Calgary planning region to alleviate *load* thermal and voltage constraints.[62] Hence, changes in customers' consumption decisions in Calgary are unlikely to drive the same change in transmission costs associated with the identified investments in the Northwest.

119. In developing our Recommended Rate Design, we have been asked to assume that rates cannot differ based upon the location of load on the transmission system.[63] Absent the ability to differentiate the marginal cost component of the tariff by location, a tariff that reflects the marginal cost of transmission would be unable to account for the fact that the marginal cost of accommodating demand in some areas is likely to be positive, while

62 AESO, AESO 2020 Long-term Transmission Plan, January 2020.

63 Norton Rose Fulbright, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, April 11 2021, Assumption C. See Attachment 1A.

the marginal cost of accommodating demand in other areas may be zero or even negative.

120. Therefore, the marginal cost component of the tariff would inevitably differ from the marginal cost of transmission associated with accommodating an additional unit of demand at that particular location of the network. As such, a tariff set using a marginal cost approach would not necessarily lead to an efficient outcome.

121. To take a practical example, where the legislation is different, the electricity transmission pricing methodology in Great Britain sets tariffs that seek to approximate the long-run marginal cost of transmission, such that transmission users receive a forward-looking signal regarding the costs they impose on the grid. However, the primary purpose of these forward-looking signals is to send locational signals regarding the long-run investment cost users impose on the grid in different *locations*, with charges for demand customers varying from £20.38 to £61.68 ($35.33 to $106.91) per kW per year, depending on location.[64] Customers also pay a non-locational charge per kW to cover residual costs.

122. Hence, even if marginal cost-based distribution tariffs may have the potential to encourage the efficient use of distribution systems in Alberta, the legislative framework in Alberta limits the potential benefits of a marginal cost methodology to set *transmission* tariffs. The relative importance of locational signals at the transmission system level compared to the distribution system level is recognized in the Distribution System Inquiry:[65]

> *"experts indicated that while there may be merits of locational pricing on the transmission system, there probably is much less value in locational pricing on the distribution systems, at this time."*

123. Whilst we assess that the use of a marginal cost-based approach for transmission pricing in Alberta is limited principally by the inability to vary the marginal cost component of

64 Half-hourly demand tariff reported for zones in Northern Scotland and South Western in Transmission Network Use of System Tariffs in 2021-22. See: National Grid, Final TNUoS Tariffs 2021-22, January 2021, Table 9. Currency converted using current exchange rate of GBP 1: 1.73 CAD.

65 AUC, Distribution System Inquiry 24116-D01-2021, 19 February 2021, para 317.

the tariff by location, using such a methodology to set transmission tariffs would also entail challenges associated with the recovery of the remaining residual costs.

5.2.2. The recovery of residual costs can obscure the marginal cost price signal

124. The large increase in transmission investment seen since 2014 has not been accompanied by significant growth in coincident peak demand.[66] Over this historical period, load growth has also been relatively low. Consequently, we would expect a tariff based on a marginal cost approach to have a small marginal cost component and large residual cost component. Large residual cost components of the tariff are challenging to recover without distorting the efficient price signal sent by the marginal cost component of the tariff.

125. As we explain above, under a Ramsey pricing approach, residual costs could be recovered from customers in proportion to their estimated price elasticities of demand (higher charges levied on customers with lower price elasticities of demand). However, estimating the price elasticity of demand for different customer groups is difficult in practice. Moreover, it involves levying costs on customer classes based on their willingness and/or ability to respond to charges. This approach would not seek to follow principles of cost causation but instead target the minimal customer response to the residual component of the tariff. Ramsey pricing to recover residual costs may also raise equity concerns because costs are recovered on the basis of least elastic billing determinants or customer groups, without consideration of the size or characteristics of the customer.

126. Hence, a more practical implementation might be to levy the residual costs on billing determinants that are less likely to produce a response from the customer. For instance, the Distribution System Inquiry states that residual costs should be recovered from billing determinants that are non-avoidable, or difficult to avoid, such as fixed monthly charges or "non-bypassable demand charges" such as non-coincidental peak demand or contract capacity charges.[67]

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[66] AESO, Bulk and Regional Tariff Design Stakeholder Engagement 4, 10 December 2020, Slides 47-48, available at https://www.aeso.ca/assets/Uploads/Presentation-Session-5.pdf.

[67] AUC, Distribution System Inquiry 24116-D01-2021, 19 February 2021, para 309.

127. However, unlike distribution systems, a relatively small number of customers are connected to the transmission system, and they vary materially in terms of their size and usage of the system. For instance, transmission-connected customers comprise small and large industrials, some of which make very little use of the grid except as a back-up to on-site generation, as well as distribution systems. Therefore, levying a fixed fee per customer or connection point to recover transmission residual costs would not follow principles of cost causation, and is likely to lead to inequitable charges as small customers would make the same financial contribution to residual costs as much larger customers, despite their differing impacts on transmission costs.

128. In addition, all transmission charges are avoidable for many transmission customers. As explained above, large industrial customers that connect directly to the transmission system can choose to reduce their coincident or non-coincident demand by self-generating, or disconnecting from the grid and self-supplying the entirety of their energy needs. Even a fixed charge per customer per month may be avoidable for a large industrial customer connected to the transmission grid.

129. As noted above, as an alternative to recovering residual costs from the customers with least price elastic demand or the billing determinants that are least avoidable, an alternative approach would be to use proportional mark-ups to uplift marginal cost-based tariffs. In this case, it is likely that proportional mark-ups would need to be large given the relative size of residual costs relative to marginal costs. Therefore, proportional mark-ups will likely significantly distort any price signal sent by the marginal cost component of the charge.

130. However, as we discuss above, the limitations associated with efficient recovery of residual costs are secondary to the limitations associated with the inability of the transmission tariff to accurately reflect marginal cost unless it has locational differentiation.

5.2.3. The lack of locational pricing would restrict or negate the efficiency benefits from the AESO introducing a marginal cost methodology

131. Economic theory shows that marginal cost prices may send more efficient signals to consumers of the impact of changes in load on the costs of transmission. However,

these theoretical benefits of a marginal cost approach cannot be realized in the AESO's context, if the transmission tariff cannot vary based upon the location of load.

132. In simple terms, the AESO provides transmission capacity to move electricity from areas where the supply of in-merit energy exceeds demand, to areas where demand exceeds supply. Increasing demand in areas of surplus in-merit energy may therefore reduce transmission costs (implying a negative marginal cost), while higher demand increases transmission costs in areas where demand exceeds supply (implying a positive marginal cost). A marginal cost-based tariff that applies in all areas cannot reflect these differences and therefore would not achieve its objective of signalling the marginal transmission costs associated with accommodating changes in demand in Alberta.

5.3. Embedded Cost Approaches

133. The AESO's Current Rate Design is an embedded cost approach. In contrast to the marginal cost approach, which aims to set a forward-looking signal regarding the additional costs that would be associated with future load growth, the embedded cost approach designs tariffs based on historical spending on capital investment and operating expenses during a specific time period.[68]

134. The process of computing an embedded cost tariff typically involves three steps, which seek to identify the historical costs associated with particular types of service provided to utility customer classes, and/or types of customer usage patterns:[69]

A. Functionalization of costs by purpose. Historically, and as described in the NARUC manual, functionalization refers to a vertically integrated utility with operations across different functions such as production, transmission, distribution, and customer service;[70]

B. Classification of costs between demand-related, energy-related, and customer-related costs; and

C. Allocation of costs to customer classes.

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68 NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 12-14.

69 NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 18-22.

70 NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 18-19.

135. The methodology depends on the unique circumstances in which the utility – or in this case the AESO – operates.[71]

136. In this context, the embedded cost methodology seeks to signal to customers the long-run costs of providing transmission, in a way that identifies which costs have been incurred historically to accommodate (or have been caused by) particular patterns of usage, particular customers, and/or particular services. The elements of an embedded methodology outlined above (i.e. functionalization, classification and allocation) need to be designed to achieve this objective, and thereby send signals to users regarding the historical costs associated with their usage of the transmission grid.

137. By setting charges to reflect the costs incurred historically to serve particular customers or types of grid usage, the embedded methodology can send signals through tariffs that reflect such patterns of cost causation. By ensuring that the structure of tariffs (the balance between fixed, demand-related, and energy-related tariffs) reflects the cost structure of the transmission grid, the tariff can encourage efficiency in users' decisions on how to use the transmission grid.

138. Embedded cost approaches may also be more straightforward than marginal cost approaches, because they rely upon known and measurable costs incurred by utilities.

139. The embedded cost approach is commonly criticized for sending less efficient price signals to consumers, because prices may not reflect the cost of consuming the next unit of electricity. Instead, prices reflect the historical, average cost of service, so consumption decisions made in response to the tariff may be less efficient than if the tariff were set equal to marginal cost.

140. However, in this particular context, i.e. electricity transmission in a jurisdiction where locational differentiation of transmission tariffs is not permitted, this common criticism of the embedded methodology would be unjustified. As we explain above, the AESO's Bulk and Regional tariff cannot accurately reflect the marginal cost of transmission without varying rates based on the location of load on the transmission system.

[71] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 22.

141. Given this limitation of marginal cost-based pricing in this context, an embedded methodology provides a reasonable guide to the costs associated with particular customers' usage of the transmission system. We therefore recommend that a tariff based on an embedded cost approach is more likely to meet cost causation principles than a tariff based on marginal cost pricing methods.

5.4. Conclusion: Retain and Improve Current Embedded Approach

142. Having evaluated both the marginal and embedded cost approaches to AESO's Bulk and Regional tariff design, we conclude that the marginal cost approach does not meet cost causation principles, principally due to the institutional context in Alberta limiting the ability to send location-specific price signals.

143. Therefore, we assess that the embedded cost approach better fits the legislative framework and characteristics of the Alberta transmission system.

144. Based on our analysis of the drivers of transmission costs, we recommend a number of improvements to the Current Rate Design, intended to ensure it reflects the drivers of transmission investment in Alberta. We set out our recommended improvements in the following section.

6. Section 6 - Improvements to the Current Embedded Cost Approach

6.1. Classification of the Costs Associated with Accommodating the Flow of In-Merit Energy

6.1.1. The tariff should separately identify the costs associated with accommodating the flow of in-merit energy

145. As we discuss in Section 3.3, the AESO needs to recover transmission costs associated with investments that it plans to accommodate flows of in-merit energy and meet the Transmission Regulation. We explain in Section 3 that the costs associated with accommodating flows of in-merit energy are not explicitly identified or classified in the Current Rate Design.

146. The Transmission Regulation requires the AESO to plan such that the transmission system is "*sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy… can occur when all transmission facilities are in service*" and so that 95 percent of the time, transmission of all such electric energy can occur under abnormal operating conditions. Should the need arise, we understand that it is the duty of AESO to arrange for expansions of the transmission system to meet this requirement, or else adopt non-wires alternatives to providing additional transmission infrastructure to ensure it can accommodate flows of in-merit energy. This planning standard requires the AESO to plan the system to accommodate flows of in-merit energy in all hours of the year in Alberta.[72]

147. The investments that the AESO makes to accommodate flows of in-merit energy are not necessarily related to changes in demand. Even if demand across Alberta remained constant over the next decade, the AESO would still plan transmission investments associated with the changing pattern of flows of in-merit energy. For instance, as we explain in Section 3.3, the retirement of coal plants and the integration of renewables may require additional transmission infrastructure to accommodate changes in the supply mix that are unrelated to demand, and instead are needed due to changes in the flow of in-merit energy.

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72 Transmission Regulation, Alta Reg 86/2007, Section 15. AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 2.

148. Under the Current Rate Design, the wires costs associated with the AESO's planned investments to accommodate flows of in-merit energy would not be treated differently from costs associated with the AESO's planned investments to accommodate demand growth. More specifically, under the Current Rate Design:

A. A cost incurred to accommodate flows of in-merit energy would be functionalized between the bulk and regional system cost pool based on the net book value of the underlying assets distinguished by voltage, similar to all other wires costs.

B. It would then be allocated between demand and energy using an allocation factor determined by a minimum system methodology that does not consider the reason why the wires costs were incurred and how they are used, i.e. whether they are used to accommodate load growth, or to accommodate flows of in-merit energy.

C. Rather, the minimum system approach in the Current Rate Design is similar to approaches used in distribution rate design and assumes representative types and costs of transmission assets that TFOs would use in the minimum and optimal system. The current methodology does not consider whether the resulting minimum system would be sufficient to meet demand, or whether any portion would be required to accommodate flows of in-merit energy.

D. Hence, all costs would be recovered from the same billing determinants, irrespective of what proportion of the network is in place to ensure demand can be served, and what proportion is in place to accommodate flows of in-merit energy.

149. Therefore, the Current Rate Design could better meet principles of cost causation by explicitly recognizing the costs associated with the investments needed to accommodate flows of in-merit energy, as distinct from those required to accommodate demand. We recommend that the AESO classifies costs between those associated with demand and those associated with accommodating flows of in-merit energy in the tariff to better reflect cost causation. We explain our recommended method for achieving this in Section 6.1.4 below.

6.1.2. The tariff should classify costs associated with accommodating the flow of in-merit energy prior to functionalization of costs by voltage

150. As part of the planning process, the AESO identifies areas of the network in which additional transmission capacity may be needed.[73] Subsequently, within any project application to the AUC, the AESO identifies the main drivers behind transmission investments, e.g. whether the investment is primarily purposed to accommodate demand or flows of in-merit energy.[74] This same process is followed, irrespective of the type of technical solution proposed by the AESO (e.g. the size of the assets, the length of lines, or their voltage level).

151. It is therefore cost-reflective for the rate design to recognize the planning process by classifying non-POD costs into the main drivers of investment requirement (serving demand and accommodating flows of in-merit energy) before a more granular functionalization and allocation of costs to different types of transmission system usage, e.g. meeting coincident peak, non-coincident peak, and energy consumption.[75]

152. We understand that when the AESO is designing the best planning solution to accommodate flows of in-merit energy, it adopts a holistic view that does not distinguish planning solutions purely on the basis of line voltage.[76] In other words, transmission assets at all transmission voltage levels can be used to accommodate flows of in-merit energy. While we assess that transmission assets required to accommodate demand can be functionalized on the basis of voltage, as we discuss in Section 6.2, this is not the case for transmission assets used to accommodate flows of in-merit energy.

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[73] AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 2.

[74] AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 3.

[75] Our Recommended Rate Design sets charges that are expected to recover the AESO's Bulk and Regional costs (i.e. non-POD costs) each year. In order to calculate the non-POD costs to be recovered through our Recommended Rate Design, we recommend the AESO functionalizes total wires between POD and non-POD using the same functionalization approach and calculations that we outline in Section 6.2 below.

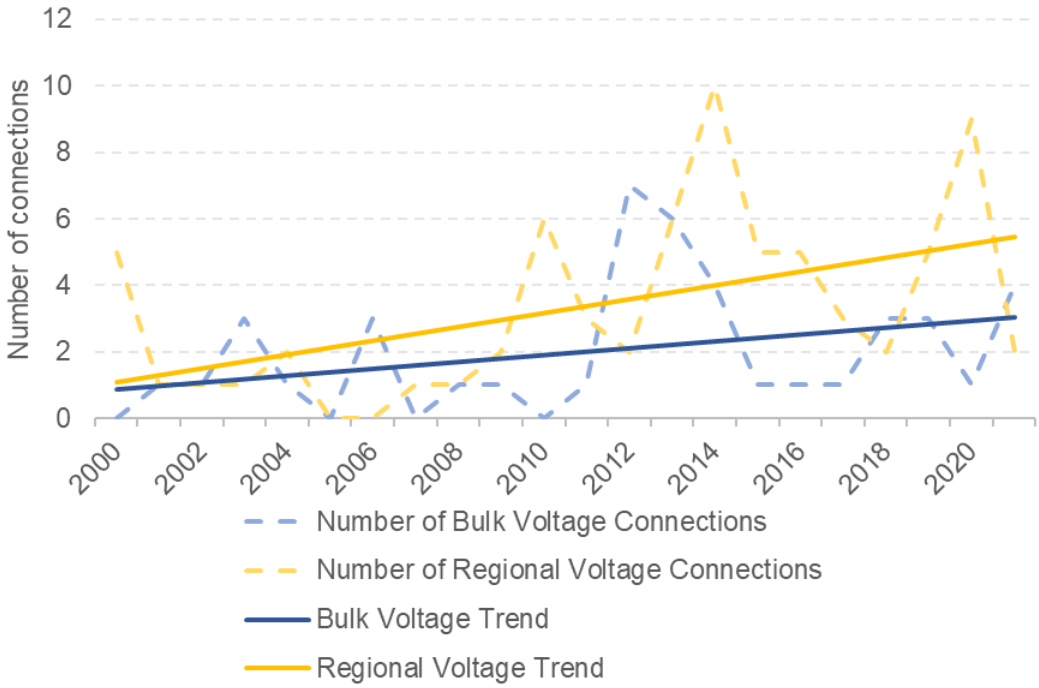
[76] For example, in the AESO's Needs Identification Documents for proposed transmission projects, the AESO identifies the need for transmission investment prior to consideration of potential solutions to provide the transmission. When assessing the transmission investment required, the AESO assesses a range of potential solutions which may vary by the voltage of underlying assets.

For example, in the assessment of alternatives to accommodate the Stirling Wind Project Connection, the AESO considered both 138kV and 240kV potential solutions to connect the wind project. Source: AESO, Application of the Alberta Electric System Operator for Approval of the Stirling Wind Project Connection Needs Identification Document, 12 December 2017, Section 2.4.

153. As we explain in Section 3.3, the changing pattern of flows of in-merit energy are partly driven by the changing location of in-merit generators. Generators connect to both the bulk and regional systems (as distinguished by voltage under the Current Rate Design). Generators are increasingly connecting at the regional system voltage level relative to the bulk system voltage level, as Figure 8 below shows.

A. We understand that generators connecting to the system prefer to do so at lower voltages to minimize their connection costs, but sometimes the AESO proposes higher voltage solutions to meet wider system needs or because lower voltage solutions are not feasible.[77]

Figure 8: Generation connections per year at regional system voltages are rising faster than connections per year at bulk system voltages



Source: See Attachment 5F; NERA analysis of AESO Connection Data.

154. Therefore, given that generation connects at both bulk and regional system voltages, and that the AESO's planners adopt a holistic view that does not distinguish planning solutions purely on the basis of line voltage, we recommend that the AESO classify

[77] For example, the AESO proposed to connect the Strathcona Cogeneration Facility through a bulk transmission line (240kV) despite considering regional system line (138kV) alternatives. Source: AESO, Application of the Alberta Electric System Operator for Approval of the Strathcona Cogeneration Facility Connection Needs Identification Document, 12 December 2018.

non-POD costs between demand and accommodating flows of in-merit energy *prior* to functionalization of costs into bulk and regional system costs.

155. Our recommendation to classify non-POD costs between demand and accommodating flows of in-merit energy prior to functionalization aligns the rate design more closely with the AESO's planning process, thereby improving the cost reflectiveness of the tariff. As we discuss above, classifying costs between demand and accommodating flows of in-merit energy reflects that the AESO first identifies the need for investment in its planning process, before examining technical solutions and developing planning alternatives.

156. The Current Rate Design classifies costs after functionalization, which does not reflect the AESO's planning process to identify the need for investment prior to selecting a planning solution. As we discuss in Section 3.3.3, the Current Rate Design also does not explicitly classify costs between those required to accommodate demand and those to accommodate flows of in-merit energy.

157. Classifying non-POD costs prior to functionalization better reflects the AESO's planning process which first examines the purpose of investments, irrespective of their voltage. Explicitly classifying costs associated with accommodating flows of in-merit energy prior to functionalization therefore better meets our evaluation criterion of cost causation, as defined in Section 4.

6.1.3. We considered an alternative where we functionalized costs prior to classification of costs

158. As an alternative, we considered maintaining the approach under the Current Rate Design whereby costs are functionalized into those related to the bulk and regional systems prior to any further allocation or classification of costs between demand and energy.

159. While the Current Rate Design has an energy charge, neither that charge, nor the rest of the rate design explicitly accounts for the transmission costs associated with accommodating flows of in-merit energy. In other words, the Current Rate Design does not classify costs between demand and accommodating flows of in-merit energy at all.

160. Moreover, functionalizing costs prior to classification is not reflective of the AESO's planning process, which considers the need for investments prior to selecting the technical solution to the identified need for transmission capacity.

161. Functionalizing assets – whether on the basis of voltage or another metric – prior to classifying costs does not follow principles of cost causation as it does not reflect that different types of assets can perform a similar function. Our recommended approach reflects that assets at different voltages, different capacities, and different line lengths can all potentially be used to serve demand or accommodate flows of in-merit energy. Our recommendation to classify costs prior to functionalization better reflects the AESO's planning process and better meets principles of cost causation.

6.1.4. We classify costs between demand and accommodating the flow of in-merit energy

162. The Current Rate Design distinguishes between demand and energy using a minimum system approach, after functionalizing between bulk and regional costs.[78] However, as we discuss in Section 6.1.1, this approach does not recognize and classify costs according to the dual purposes of electricity transmission in Alberta (meeting peak demand and accommodating flows of in-merit energy).

163. We recommend retaining a minimum system approach as part of the cost classification stage. Specifically, we recommend estimating the portion of costs that constitute the minimum system required to serve peak load in Alberta. The actual system may be greater in size than the minimum system required to meet peak load in Alberta because the AESO's planning standards require it to plan to accommodate flows of in-merit energy in all hours under normal system operating conditions. Therefore, we also recommend estimating the size of the actual system required to accommodate flows of in-merit energy in all hours.

164. To define the minimum and actual systems we use historical data that characterizes how the transmission system in Alberta is used to serve demand and to accommodate flows of in-merit energy. This analysis does not seek to quantify the exact size of the

78 AESO, 2018 ISO Tariff Application – Appendix D Transmission System Cost Causation Study 2018 Update, 14 September 2017, p. 25-28.

minimum and actual systems, but to use metered data to estimate the portion of costs that constitute both systems based on the historical use of transmission across planning areas.

165. We used metered net DTS load and generation in our analysis.[79] Using actual metered data to estimate the minimum and actual systems means that our estimation will reflect how the transmission system is actually used in Alberta, and will change over time as the system evolves with changing demand and flows of in-merit energy.

166. More specifically, we examined metered net load and metered generation in each planning area in Alberta (illustrated in Figure 3). As we discuss in Section 2.2, the AESO uses load and generation data aggregated at different levels in its transmission planning. Specifically, POD data, planning area data, planning region data, and total system-level data.[80] We consider planning area data the most appropriate aggregation of data to use when identifying the minimum and actual systems because:

A. Analysis of system-level or planning region data will understate the variation in the different uses of the transmission grid because the data is aggregated across large zones of the network. Use of this data would systematically understate the degree to which the transmission network is used to accommodate flows of in-merit energy within the system or planning regions respectively.

B. POD data is highly granular and would not allow us to consider the diversity of demand and supply within relatively local areas of the network, which we understand the AESO would do as part of the planning process.[81]

C. We consider that the AESO's planning area data reasonably balances these considerations, allowing us to examine the different uses of the Bulk and Regional transmission system.

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79 Net load does not include load that is served through behind the meter generation. Generation does not include auxiliary use nor behind the meter generation by customers choosing to self-supply.

80 See for instance, in the AESO's discussion of its 2019 LTO load forecast in the 2020 Long Term Transmission Plan: "The tool models Alberta load across different granularities, i.e., POD, areas, regions, and the whole province". Source: AESO, AESO 2020 Long-term Transmission Plan, January 2020, p. 12.

81 "Planning for regional and sub-regional system takes into account coincident load for the study area as well as individual customer highest load and contracted load". Source: AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 4.

167. We estimate the minimum and actual transmission system in each planning area through analysis of metered hourly data in a "reference year." The reference year could be the last full year available at the point of setting the tariff, or alternatively, the AESO could update the reference year once every few years or when there are significant changes to flows of in-merit energy. We demonstrate in Figure 10 below that the resulting classification of costs is relatively stable over time, and therefore updating the reference year every year may not be needed to set cost reflective tariffs.

168. Our recommended approach estimates the overall minimum and actual system in Alberta by examining the minimum and actual systems across planning areas. In each planning area:

A. As a proxy for the size of the minimum transmission system that is required to ensure that peak load can be served, we identify the maximum hourly metered net load in the planning area during the reference year in MW.[82] By using net demand rather than gross demand, we account for the extent to which demand is served by generation located behind the meter.

B. To estimate the actual system in the area, we assess whether the transmission system required to accommodate flows of in-merit energy in each planning area exceeds the size of the minimum transmission system required to serve peak load. As a proxy for the transmission system size required to accommodate flows of in-merit energy in each planning area, we identify the maximum hourly generation during the reference year in MW.

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[82] The hourly metered DTS area load data requires cleaning prior to its use in calculations. In particular, there are three hours of load data each year which require attention:

(1) The first hour of the day in which the clocks change in March. The first hour of the day in which the clocks change in March incorrectly reports load in the metered data, reporting a value for load which is approximately double the typical hourly load in the area. We treat this hour by dropping the observation.

(2) The hour of 7 to 8pm on the day prior to the clock change in March each year. This hour reports load which is metered in error, and is systematically lower than typical load across hours. We treat this hour by dropping the observation.

(3) The additional hour on the day the clocks move back in November. There are 25 hours of metered data on the day the clocks move back in November. However, one of these hours is reported as a #REF error in the underlying data. We drop this observation.

The generation data is unaffected by these errors in the source data.

C. In areas where peak generation (step B) exceeds peak load (step A), the actual transmission system needed to accommodate flows of in-merit energy will need to be greater in size than the minimum system to meet peak load in the area. Therefore, we define the size of the actual system in the planning area by metered peak generation. In areas where the actual transmission system is larger than the minimum system, we recommend that the additional system above the minimum system is classified as being required to accommodate flows of in-merit energy. We recommend the minimum system be classified as required to meet demand.

D. In areas where peak load (step A) exceeds peak generation (step B), the minimum system to meet peak load is sufficient to also accommodate flows of in-merit energy in the planning area. In these areas, we recommend that the area minimum system is classified as being required to meet demand, but there is no additional system required to accommodate flows of in-merit energy. Therefore, the actual system is the same size as the minimum system in the area.

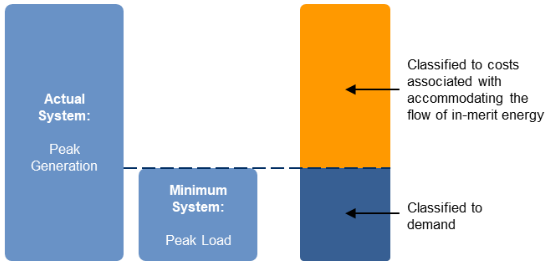
169. We illustrate our recommended minimum system approach in Figure 9 below:

A. In “Example A” on the left of the Figure, peak generation (100 MW) is higher than peak load (35 MW), so the peak in generation defines the size of the actual system in the planning area (100 MW). The minimum system in the area is defined by peak load (35 MW). The difference between the actual and minimum systems, shown in the orange part of the bar in Example A, is required to accommodate flows of in-merit energy.

B. In “Example B” on the right of the Figure, peak generation (100 MW) is less than peak load (120 MW) in the planning area. Therefore, we estimate that the transmission system required to serve load is also sufficient to accommodate flows of in-merit energy and therefore the minimum and actual systems are of identical size.

Figure 9: Illustrative Examples of the Minimum System Approach

Example A: An area where the minimum system is not large enough to accommodate the flow of in-merit energy: *Classification of costs between demand and those associated with the accommodation of the flow of in-merit energy*

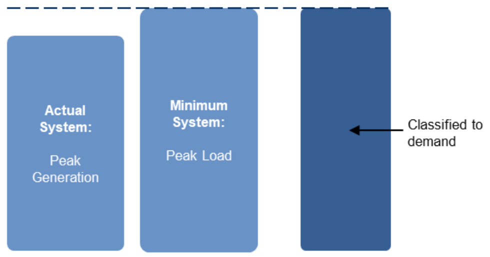


Hour of Ref. Year	Area Load (MW)	Area Generation (MW)
1	25	90
2	30	**100**
3	**35**	90
…	…	…
Area Peak:	**35 MW**	**100 MW**

$$Area\ Minimum\ System = Peak\ Area\ Load = 35\ MW$$

$$\begin{aligned} Area\ Actual\ System &= \max(Area\ Minimum\ System, Peak\ Area\ Generation) \\ &= \max(35\ MW, 100\ MW) \\ &= 100\ MW \end{aligned}$$

Example B: An area where the minimum system is large enough to accommodate the flow of in-merit energy: *Classification of all costs to demand*



Hour of Ref. Year	Area Load (MW)	Area Generation (MW)
1	100	90
2	95	**100**
3	**120**	90
…	…	…
Area Peak:	**120 MW**	**100 MW**

$$Area\ Minimum\ System = Peak\ Area\ Load = 120\ MW$$

$$\begin{aligned} Area\ Actual\ System &= \max(Area\ Minimum\ System, Peak\ Area\ Generation) \\ &= \max(120\ MW, 100\ MW) \\ &= 120\ MW \end{aligned}$$

Source: NERA Illustration.

170. Having estimated the size of the minimum and actual system for each of the AESO's 42 planning areas, we then aggregate the results of the individual planning areas to define the overall minimum system and overall actual system for the entire province of Alberta. We sum the area minimum and actual systems that we estimate across all 42 planning areas to calculate the overall minimum and actual systems across the province respectively (see Attachment 3B for our calculations).

$$Overall\ Minimum\ System = \sum_{1}^{42\ planning\ areas} Area\ Minimum\ System$$

$$Overall\ Actual\ System = \sum_{1}^{42\ planning\ areas} Area\ Actual\ Systems$$

171. Finally, we calculate the proportion of the overall actual system constituted by the overall minimum system. This proportion determines our demand classified costs. The

remaining costs are classified to those associated with accommodating flows of in-merit energy (see Attachment 3B for our calculations).

$$Classification\ of\ Costs\ to\ Demand = \frac{Overall\ Minimum\ System}{Overall\ Actual\ System} \times 100\%$$

$$Classification\ of\ Costs\ to\ Accommodation\ of\ Flows\ of\ In - Merit\ Energy = 100\% - Classification\ of\ Costs\ to\ Demand$$

172. For example, using the same illustrative example as we set out in Figure 9 above and assuming that the entire province was constituted by the two areas in Examples A and B, the overall classification of costs would be calculated as follows:

A. The overall minimum system would be 155 MW, calculated as the sum of area minimum systems in Examples A and B which are 35 MW and 120 MW respectively.

B. The overall actual system would be 220 MW, calculated as the sum of actual systems in Examples A and B which are 100 MW and 120 MW respectively.

C. The classification of costs to demand would be calculated as follows:

$$Classification\ of\ Costs\ to\ Demand = \frac{155\ MW}{220\ MW} \times 100\% = \mathbf{70}\%$$

D. The classification of costs to those associated with accommodating flows of in-merit energy would be calculated as follows:

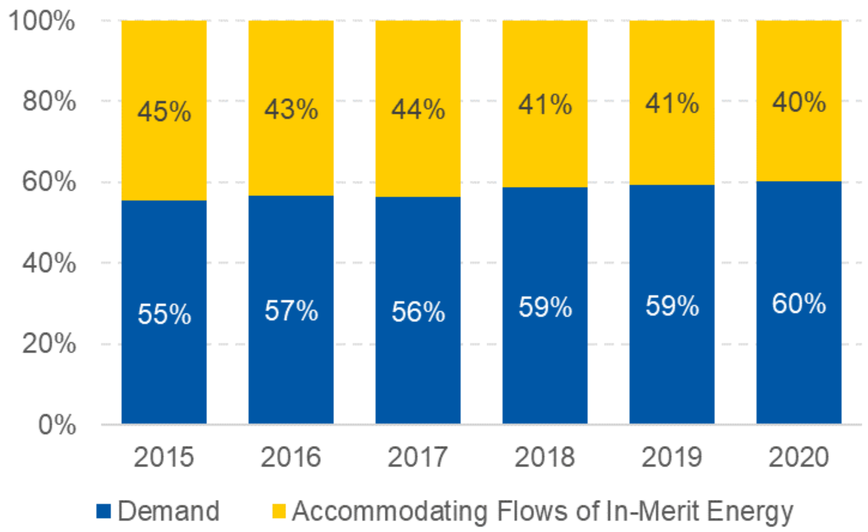
$$Classification\ of\ Costs\ to\ AFIME = 100\% - 70\% = \mathbf{30}\%$$

173. Using 2019 metered data as our reference year, we used our recommended approach to estimate the size of the overall minimum and actual system in Alberta. We estimated that the minimum system is 59 percent of the size of the total actual system in Alberta. Therefore, our recommended approach means we classify 59 percent of total non-POD wires costs to demand and the remaining 41 percent of costs as those associated with accommodating flows of in-merit energy.

174. For clarity, and as we explain in Section 6.1.2, we perform the classification of costs between demand and energy prior to any functionalization of costs. Therefore, our classification of costs is applied to total non-POD wires costs.

175. We repeat our calculation using metered data in 2015-2020. As we show in Figure 10, the shares of demand-classified and costs classified to accommodating flows of in-merit energy are relatively stable over time.

Figure 10: Classification of Demand- and In-Merit Energy-Related Costs Under Our Recommended Minimum System Approach



Source: See Attachment 3B and 5G; NERA analysis of area-level load and generation data provided by the AESO.

176. Our recommended approach is an improvement to the current minimum system approach because it uses metered load and generation data that proxies the actual use of the system across planning areas in each calendar year. Moreover, our definition of the actual system reflects the additional flows of in-merit energy above peak demand that require the AESO to plan for a larger transmission system than that required to meet peak load.

177. By utilizing historical data to set the transmission tariff, our recommended approach updates the classification of costs based on the changing use of the system over time. This is particularly important, given the expected changes in the generation fleet in the future, as we discuss in Section 3.3. Our recommended method will account for the changing location of in-merit energy flows by examining changes in data for each planning area over time:

A. For example, if a new generator connects in a planning area, peak generation may rise relative to peak load. Applying our recommended method would result in an increase in costs classified to accommodating the flow of in-merit energy, which reflects that the AESO needs to plan to accommodate flows of in-merit energy from the new generator, assuming no other changes and that the actual system in the area is at least as large as the minimum system before the new generator connects.

B. Alternatively, following the decommissioning of a generator in a planning area, peak generation may fall relative to peak load. Therefore, applying our recommended method would result in an increase in the share of costs classified to demand, assuming no other changes and that the actual system in the area is larger than the minimum system before the plant decommissions.

6.1.5. Alternatives Considered: We considered alternative methods to classify costs between demand and accommodating the flow of in-merit energy

178. We considered three alternative methods to classify costs between demand and accommodating the flow of in-merit energy before recommending the approach set out above:

A. We considered classifying costs based on the historical reason for the investments made by the AESO's planners;

B. We considered using a minimum and actual system approach, but defining the minimum system using peak load in each area and the actual system using the annual peak in hourly net generation (i.e. generation less demand) in each area (instead of the annual peak in hourly generation under our recommended approach); and

C. We considered using our recommended minimum and actual system approach, but defining the minimum system using contract capacity and the actual system using generation capacity.

179. We set out each of these three alternatives, and the reasons we do not follow them in the subsections below.

6.1.5.1. Alternative 1: Classification of costs based on the historical reason for investments

180. We considered classifying costs based on the historical reason for the investments proposed by the AESO's planners. We could attempt to identify the original purpose of each investment in the Alberta system, and whether it was planned to meet demand or to accommodate flows of in-merit energy. We could then classify costs to those associated with demand in proportion to the total costs of investments planned to meet demand as a proportion of total investment costs. The remaining proportion would be classified as being associated with accommodating flows of in-merit energy.

181. In theory, an allocation of individual investments could provide a more accurate classification of costs, as it would avoid the need to use proxy measures for the size of the minimum and actual systems under our recommended approach by classifying costs associated with specific investments.

182. However, there are significant shortcomings to this approach in practice:

A. Identifying which investments should be classified to demand and which investments should be classified to those that accommodate flows of in-merit energy would be imprecise when projects have a joint purpose. For instance, a transmission asset may be built to accommodate new generation, but also enable higher peak demand to be served. In these cases, apportioning the fraction of the investment attributable to meeting peak demand as opposed to accommodating flows of in-merit energy would be imprecise.

B. The methodology would be difficult to implement when the role of individual assets evolves over time. Following changes in the supply-demand mix across the system, assets may be utilized for a different purpose than initially expected when they were planned. This may be particularly true following retirement and commissioning of generation capacity in different locations on the transmission network. In these cases, identifying and updating the fraction of investment costs attributable to meeting peak demand as opposed to accommodating flows of in-merit energy would be difficult.

183. Overall, we discard this alternative in favour of our recommended approach. While our recommended approach does proxy for the size of minimum and actual systems through

using peak load and peak generation respectively, its use of metered data means it accounts for changes to how the grid and assets are used over time and the corresponding classification of costs. It is also more practical to implement than attempting to classify costs of individual investments based on the reason for those investments.

6.1.5.2. Alternative 2: Classification of costs using an actual system defined using net generation

184. We also considered alternative ways of defining the minimum and actual systems in our recommended method. Under our recommended approach we: (i) estimate the minimum system in each planning area based on peak hourly load in the area in the reference year, and (ii) estimate the additional transmission required for the actual system based on peak hourly generation in the area in the reference year.

185. Instead of using peak load to estimate the minimum system and peak generation to estimate the actual system, we considered using peak load to estimate the minimum system and peak *net* generation to estimate the actual system in each planning area in the reference year. Under this approach, we would define peak net generation by the hour in which generation *minus* net load is the greatest across the year.

186. We considered this alternative on the basis that the peak in net generation might better capture the flows of energy in the planning area which were not used to serve load in the area, and therefore relate to the need for transmission to evacuate generation from the planning area. Therefore, using peak net generation rather than peak generation may better capture flows between planning areas.

187. However, we consider that this method does not account for the size of the actual system within the planning area that is required to facilitate the flow of in-merit generation from generators to load in the area. In other words, using net generation only considers the need to accommodate flows of in-merit energy between planning areas and implicitly assumes that no transmission within a planning area is required to accommodate flows of in-merit energy. In reality, this is unlikely to be the case, as sources of in-merit generation and sites of energy consumption may not be located next to each other within a planning area, and therefore transmission is required to accommodate flows of in-merit energy to meet energy consumption.

188. Therefore, this alternative approach likely overstates the classification of costs to demand and understates the classification of costs to those associated with accommodating flows of in-merit energy by limiting to flows within planning areas.

189. Our recommended method of using peak generation better accounts for the size of the actual system, both within planning areas and the transmission between planning areas, that is required to accommodate flows of in-merit energy.

6.1.5.3. Alternative 3: Classification of costs using an actual system defined using generation capacity and a minimum system defined using contract capacity

190. We also considered using maximum contract capacity in the year, when summed across sites, to estimate the minimum system within the planning area and maximum generation capacity in the year to estimate the actual system in each planning area.

191. We considered this alternative because it reflects that the AESO may need to plan transmission in each area to meet potential load or potential flows of in-merit energy based on the capacity that users contract for, even if they do not use it in practice. In other words, transmission in each planning area may need to be scaled such that it can accommodate flows from generators up to their capacity. Similarly, the transmission network may need to be scaled to facilitate demand at each customer site, if those customers were all consuming at their contract capacity.

192. However, using contracted demand and generation capacity does not account for diversification of load and generation, for which we understand the AESO accounts in its planning process.[83] In practice, while the AESO may need to plan to accommodate the contract capacity of a single customer, it is unlikely that the AESO needs to plan to accommodate the contract capacity of *all* of the customers in a planning area at the same time. Similarly, the AESO may not need to plan for coincident generation by all generators at their capacities, if they are not all in-merit at the same time.

193. Using this alternative approach would not reflect how the AESO plans transmission within planning areas and may consequently overstate or understate the classification

83 "Planning for regional and sub-regional system takes into account coincident load for the study area as well as individual customer highest load and contracted load". Source: AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 4.

of costs to demand, depending on the degree of diversification of load relative to generation that is not accounted for in the approach.

194. Our recommended approach examines peak flows associated with demand and in-merit energy which capture the coincidence of load and generation in the area, including customers or generators wishing to demand or generate at their capacity. Therefore, we find that our recommended approach more closely reflects how the AESO plans transmission within planning areas and is more appropriate to estimate the size of minimum and actual systems.

6.2. Functionalization of Demand-Driven Costs

195. Having classified costs, we have two pools of costs: those associated with demand and those associated with accommodating flows of in-merit energy. We then need to functionalize the remaining demand-driven costs, to reflect the function performed by different transmission assets to meet demand across the system.

196. Functionalizing demand-driven costs is necessary to reflect cost causation and meet our evaluation criteria as we set out in Section 4. Under the current tariff which functionalizes costs based on voltage, we recognize that:

A. Higher voltage lines are more likely to be used to transmit power in bulk over long distances, predominantly in order to meet demand at times of coincident system peak, when demand across the system is highest; whereas

B. Lower voltage lines are more likely to be used to meet non-coincident peak demand within localized systems, connecting demand from sites and planning areas to the bulk system.

197. Therefore, we recommend functionalizing demand-driven costs according to whether they are serving a bulk or regional function.

198. We recommend using a similar approach to functionalization as under the Current Rate Design, by using the net book value of underlying transmission assets delineated by voltage. Delineation of assets by voltage reflects the typical design of transmission systems which connect users at low voltage levels and step-up the voltage to high

voltage levels when connecting to a bulk system for power, for the purpose of transporting power over long distances.

199. As under the Current Rate Design, we recommend maintaining the same voltage levels for functionalizing bulk and regional system assets.

200. However, the AESO's methodology to functionalize costs under the Current Rate Design is complex because it forecasts and extrapolates costs and asset values from historical TFO data.

201. We recommend that the AESO uses updated TFO data to functionalize costs because it is simpler and more precise to implement, as it avoids the need to forecast asset values and costs into the future. To maintain this simplicity into the future, we recommend that the AESO updates the calculation once every few years when it has new TFO data, or sooner in cases when there are significant changes to the transmission assets in the network.

202. We also recommend the AESO uses the same calculations and data to functionalize demand-driven costs and to functionalize costs to POD (in order to determine the costs to be recovered from the Bulk and Regional Tariff).

203. However, the functionalization calculations that we have used in this Report rely on the AESO's historical functionalization calculations based on older TFO data.[84] We use these numbers as a holding assumption, as we understand that the AESO expects to be able to use updated data from TFOs in its calculations for the Recommended Rate Design.

204. Based on the AESO's calculation of cost functionalization in 2019, we functionalize 68 percent of demand-related costs as bulk and the remaining 32 percent as regional.[85] We apply this functionalization to the pool of demand-driven costs that we classified using our recommended minimum system approach.

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[84] AESO, Appendix-E-Transmission-System-Cost-Causation-Study-2018-Update-Workbook xlsx.

[85] AESO, Appendix-E-Transmission-System-Cost-Causation-Study-2018-Update-Workbook xlsx, Sheet "Func Results 2019", Cells "D102-F102".

6.2.1. We considered alternative methods to functionalize demand-driven costs

205. We considered two alternative methods to functionalize demand-related costs:

A. We considered functionalizing transmission lines based on their asset value delineated by transmission line capacity; and

B. We considered functionalizing transmission lines based on their asset value delineated by transmission line length.

6.2.1.1. Alternative 1: Functionalizing transmission lines based on line capacity

206. We considered functionalizing demand-driven costs based on delineating transmission lines by line capacity, on the basis that transmission assets with higher capacity are more likely to serve a bulk system purpose of transporting power in bulk. In this case, we would functionalize demand-driven costs using a similar method to that under the Current Rate Design, but by using line capacity instead of line voltage to delineate underlying assets.

207. However, we considered that some lines serving large individual customers' needs may need to have sufficient capacity to meet that customer's local peaks in demand. These lines would not be performing a bulk function by moving power around the system to meet the overall needs of the system at times of coincident peak. Instead, these lines would be performing a regional function, connecting those large customers to the bulk transmission system.

208. To illustrate this further, we also understand that the AESO has changed capacity of transmission lines in the past, but that those lines continue to serve a similar function, suggesting that line capacity is not systematically associated with the function of transmission lines.[86]

209. Consequently, functionalizing costs on the basis of line capacity would not be cost reflective, because lines with larger capacities do not necessarily perform bulk functions.

[86] See for example the Red Deer Regional Transmission Development: AESO, Application of the Alberta Electric System Operator for approval of the Red Deer Region Transmission Development Needs Identification Document, 19 July 2011, Section 3.

6.2.1.2. Alternative 2: Functionalizing transmission lines based on line length

210. We also considered functionalizing demand-driven costs based on the length of transmission lines. Longer lines may be more likely to perform a bulk system function, by moving power around the system over long distances to meet coincident system peak demand. Meanwhile, shorter lines may be more likely to perform a regional system function by connecting customers to the bulk system.

211. However, while longer lines may be needed to move power around the system, regional system lines may also have longer lengths to meet the loads of individual customers located relatively far away from the bulk system. Similarly, bulk system lines may have smaller line lengths to transport power over short distances in densely populated load centers.

212. Consequently, functionalizing costs on the basis of line length would not be cost reflective, as lines with shorter lengths may perform bulk system functions, whereas lines with longer lengths may perform regional system functions.

213. Additionally, there may be practical problems with using line length to functionalize costs. Data detailing line length may be sensitive to the connection of new lines, which may intersect and split existing current lines into smaller lengths without any change in their underlying purpose. In these cases, the line lengths would change, potentially without any change in the function of those lines.

6.2.1.3. Our recommended approach functionalizes costs based on voltage

214. As these alternatives have significant limitations, we consider that functionalization by voltage is more reflective of the function of lines in the transmission system. Transmission systems are designed to step-up voltage to higher levels to transport energy over long distances in order to achieve an economic level of losses, and step-down voltage to meet load at individual sites. Hence, functionalizing assets by voltage acts as a reasonable proxy for whether a transmission asset is serving a bulk or a regional function.

215. In addition to being supportive of cost causation, we also note that functionalization by voltage is used in the Current Rate Design. Therefore, maintaining functionalization by voltage will reduce the disruption of introducing our Recommended Rate Design.

216. Having functionalized the pool of demand-driven costs based on the net book value of the underlying assets delineated by voltage, we are left with two pools of demand-driven costs: those associated with the bulk system and the regional system.

217. We do not recommend functionalizing the pool of costs associated with accommodating flows of in-merit energy. As we explain in Section 6.1.2, the AESO's planners utilize a range of different types of assets, including those at both high and low voltages, to accommodate flows of in-merit energy. Functionalizing costs associated with accommodating flows of in-merit energy is unnecessary because all types of assets that accommodate flows of in-merit energy serve a similar function.

6.3. Allocation of Bulk System Demand-Driven Costs

218. After classification and functionalization of costs, we have three pools of costs: bulk system demand-driven costs, regional system demand-driven costs, and costs associated with accommodating flows of in-merit energy. Next, we recommend performing an additional allocation of demand-driven, bulk system costs between those associated with serving coincident peak demand and those associated with serving the non-coincident peaks in demand within areas.

219. As we discuss in Section 6.2 above, the bulk system is used to move power across the system throughout Alberta. Therefore, to the extent that the size and costs of the bulk system is driven by demand, it is predominantly driven by coincident system peak.

220. However, some parts of the bulk system may need to be larger than required to meet coincident system peak if peaks in demand in individual areas occur at other times. The costs associated with the additional transmission that the AESO plans to meet this non-coincident peak demand in areas is still demand-driven but driven by non-coincident peaks in demand instead of coincident demand across the province. Therefore, we recommend that the AESO allocates bulk system, demand-driven costs between those associated with meeting coincident peak demand across the system and those associated with meeting non-coincident peak demand in different areas of the system.

221. To perform this allocation, we examine the same net load data in each planning area and reference year that we use earlier in our Recommended Rate Design to classify costs between demand and those associated with accommodating flows of in-merit energy. More specifically, we:

A. Calculate peak load in each area across the reference year. We define peak load as the hour of the reference year in the planning area where load (measured in total MWh of demand during the hour) is highest. This is the same calculation of peak load that we use to classify costs between those associated with demand and those associated with accommodating flows of in-merit energy; then

B. Identify the hours with the highest hourly demand (in MWh) in each month of the year for the whole system, which approximates demand in the area during 12CP conditions.[87] We examine maximum peak load for each area during times of 12CP across the year.

C. Compare the peak load in the area at any time of the year (step A) with the peak load during times of coincident peak in the area (step B).

222. If peak load in the area (step A) is greater than peak load in 12CP conditions (step B), then we infer that additional bulk transmission system is required to move power from elsewhere in the province to meet non-coincident peak demand in the planning area, relative to the transmission system which is required to meet demand in 12CP conditions.

223. We illustrate our recommended approach in Figure 11 below:

A. In “Example A” on the left-hand side of the Figure, we illustrate the allocation of bulk system demand-driven costs in an area which does not require additional bulk transmission to meet its non-coincident peak demand. In the example, maximum peak hourly load in times of 12CP conditions (100 MWh) is the same as peak load during all hours of the year (100 MWh). In other words, peak load in the planning

[87] Under the Current Rate Design, each incidence of monthly coincident peak that defines the charging basis for the 12CP charge is defined by peak coincident load in each month across a 15-minute window. Our approach differs slightly by considering peak coincident load in each month across an *hourly* window. We consider an hourly window because metered data is reported on an hourly basis.

area occurs during an hour of 12CP conditions. Therefore, no additional bulk transmission is required to meet non-coincident peak demand in the planning area.

B. In "Example B" on the right-hand side of the Figure, we illustrate the allocation of bulk system demand-driven costs in an area which does require additional bulk transmission to meet its non-coincident peak demand. In the example, maximum peak hourly load in times of 12CP conditions (60 MWh) is *less* than peak load during all hours of the year (70 MWh). In other words, peak load in the planning area occurs during an hour outside of hours of 12CP conditions. Therefore, additional bulk transmission (10 MW) is required to meet non-coincident peak demand in the planning area.

Figure 11: Illustration of Our Recommended Method to Allocate Bulk System Demand-Driven Costs

Example A: An area where no additional bulk transmission is required to meet non-coincident peak demand: *Allocation of bulk system demand-driven costs to coincident peak demand.*

	Month of Reference Year	Area Load During Hours of System 12CP Conditions (MWh)
	January	90
	February	**100**
	March	90
	…	…
	December	85
A	**Area Peak at Times of 12CP Conditions**	**100 MWh**
B	**Area Peak Consumption in All Hours of Ref. Year**	**100 MWh**
C = B - A	**Additional Transmission Required to Meet Non-Coincident Peak (MW)**	**0 MW**

Example B: An area where additional bulk transmission is required to meet non-coincident peak demand: *Allocation of bulk system demand-driven costs to coincident peak and non-coincident peak demand.*

	Month of Reference Year	Area Load During Hours of System 12CP Conditions (MWh)
	January	40
	February	50
	March	**60**
	…	…
	December	55
A	**Area Peak at Times of 12CP Conditions**	**60 MWh**
B	**Area Peak Consumption in All Hours of Ref. Year**	**70 MWh**
C = B - A	**Additional Transmission Required to Meet Non-Coincident Peak (MW)**	**10 MW**

Source: NERA Illustration.

224. We then sum peak load and maximum peak load during times of 12CP across the AESO's 42 planning areas. In order to allocate costs between those associated with coincident peak demand, we calculate the total load across all areas in 12CP conditions, as a proportion of total non-coincident peak load across all areas. This ratio determines the allocation of bulk-system demand-driven costs to be recovered from a charge levied on coincident peak demand. We recommend recovering the remaining proportion of

costs from a charge levied on billing capacity, as a measure of non-coincident peak demand (discussed further below).

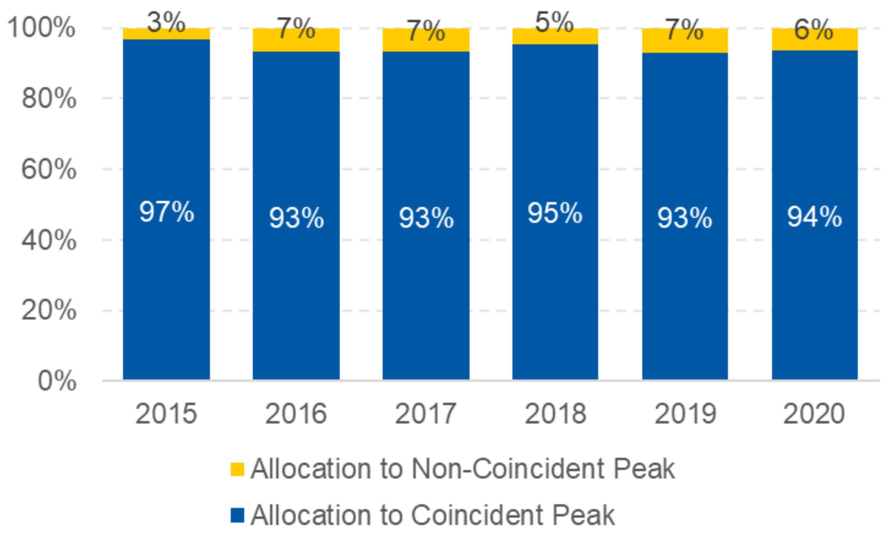
225. We calculate the allocation of bulk system demand-driven costs between those associated with meeting coincident peak demand and those associated with meeting non-coincident peak demand through the following calculation:

$$\begin{matrix}\textit{Allocation of Bulk Costs}\\ \textit{to Coincident Demand}\end{matrix} = \frac{\textit{Sum of Peak Load at Times of } 12\ \textit{CP Across Areas}}{\textit{Sum of Non-Coincident Peak Load Across Areas}} \times 100\%$$

$$\begin{matrix}\textit{Allocation of Bulk Costs}\\ \textit{to Non-Coincident Demand}\end{matrix} = 100\% - \begin{matrix}\textit{Allocation of Bulk Costs}\\ \textit{to Coincident Demand}\end{matrix}$$

226. We compute this allocation using metered area data from 2015 to 2020, as shown in Figure 12 below.

Figure 12: Allocation of Bulk System Demand-Driven Costs Between Coincident and Non-Coincident Peak Demand



Source: See Attachment 3B and 5G; NERA analysis of planning area load and generation data provided by the AESO.

227. Using the 2019 reference year, this procedure would allocate 93 percent of bulk system, demand-driven costs to a charge levied on coincident peak demand, and 7 percent of bulk system demand-driven costs to be recovered from a charged levied on non-coincident peak demand.

6.3.1. Alternatives Considered: We considered not performing an allocation of bulk system costs between coincident and non-coincident peak demand

228. We considered not performing this additional allocation and instead recovering all bulk system demand-driven costs through a charge levied on coincident peak.

229. However, this would not be cost reflective and would overstate the importance of coincident peak demand in determining demand-driven bulk system transmission costs. The bulk transmission system transports power over long distances to meet demand across the system. It is therefore primarily driven by coincident peak. However, the bulk system may need to be larger than required to meet coincident system peak if peaks in demand in different areas of the system occur at other times. These peaks are still driven by demand, and coincident peak demand over a number of customers in the area, but not by coincident peak demand across the system.

230. Therefore, to better meet principles of cost causation, we allocate the demand-driven costs associated with the additional size of the bulk system (which is also scaled to meet peak in different areas at times other than coincident peak) to be recovered from a charge levied on non-coincident peak demand.

6.4. Billing Determinants

231. After the classification, functionalization, and allocation steps, we are left with four pools of costs to recover from billing determinants:

A. A pool of bulk system, demand-driven costs associated with meeting coincident peak demand;

B. A pool of bulk system, demand-driven costs associated with meeting non-coincident peak demand;

C. A pool of regional system, demand-driven costs associated with meeting non-coincident peak demand; and

D. A pool of costs associated with accommodating flows of in-merit energy.

232. We recommend recovering these four pools of costs through three billing determinants.

6.4.1. We recommend recovering bulk system costs associated with coincident peak demand using a 12CP billing determinant

233. Under the Current Rate Design, bulk system costs classified to demand are recovered from a charge on 12CP. We recommend that the AESO maintains a charge that is based on 12CP to recover the 94 percent of bulk system, demand-driven costs that are allocated to coincident peak demand.

234. Demand-driven transmission requirements for the bulk system change across the year due to changes in both the level of coincident peak demand in each month, but also the location of that coincident peak demand relative to in-merit generation.

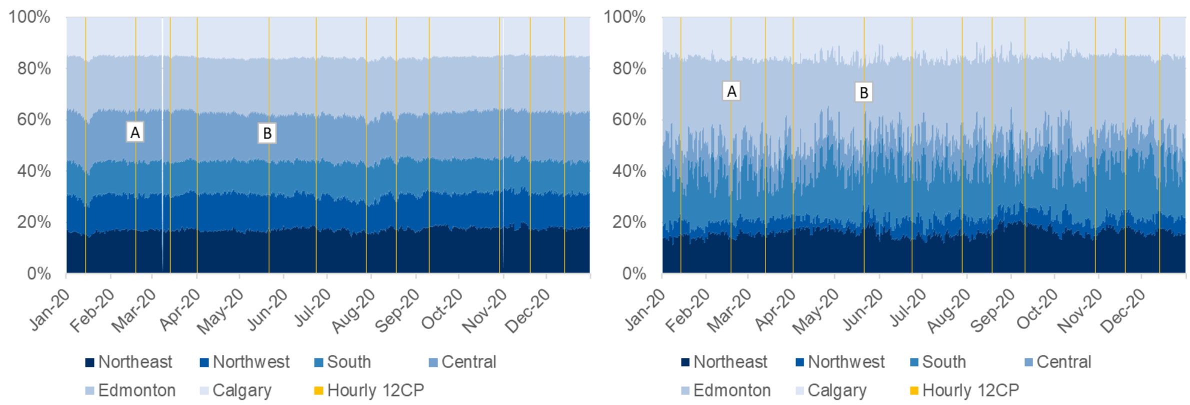
A. We recognize that we have already classified costs associated with accommodating flows of in-merit energy to a separate pool of costs. These costs are primarily associated with the transmission needed to accommodate flows of in-merit energy in all hours of the year.

B. However, the 12CP charge recovers bulk system demand-driven costs associated with the bulk transmission assets required to ensure coincident peak demand is met across the system. Changes in coincident peak demand in each month can lead to different demand-driven requirements for bulk system transmission depending on where the growth in demand occurs relative to available in-merit energy.

235. In Figure 13 below, we show the proportion of total demand and generation from each of the six planning regions of the Albertan system across hours of 2020. We indicate times of 12CP, as measured through hourly data as we discuss in Section 6.3.[88] The figure uses metered, regional load and generation data, aggregated from the same area-level data we use in the classification of costs in our Recommended Rate Design.

[88] We use regions in this illustration for simplicity i.e. to avoid displaying proportions across 42 planning areas.

Figure 13: Regional Proportions of Load (left) and Generation (right) in 2020



Load	Northeast	Northwest	South	Central	Edmonton	Calgary
A - February	15.3%	10.5%	12.8%	18.7%	24.2%	18.5%
B - May	15.9%	9.8%	11.5%	18.2%	24.6%	20.0%
Generation						
A - February	13.3%	7.1%	9.6%	14.3%	38.2%	17.5%
B - May	14.9%	6.8%	24.6%	8.3%	29.3%	16.1%

Source: See Attachment 5H; NERA analysis of area-level load and generation data provided by the AESO.

236. As the figure shows, across 2020, the regional pattern of generation relative to load changes across months. For instance, at the time of monthly peak demand in February (A), relatively more in-merit generation is located in the Central and Edmonton planning regions than at monthly peak demand in May (B) when relatively more in-merit energy comes from the South. On the other hand, the regional distribution of load across Alberta is relatively similar across both monthly peaks (A and B). Other systematic features of the Albertan system also drive changes in the regional pattern of demand at times of coincident peak relative in-merit energy. Higher output from hydropower generation in spring and summer months may also result in a different pattern of flows to meet coincident peak demand in the bulk system.[89]

237. Consequently, the need for bulk system transmission to meet coincident demand differs in each month across the year. Utilizing a charge levied on 12CP reflects the costs of providing bulk transmission capacity by reflecting that customers' contributions to

[89] Using generation data provided by the AESO from 2018-2020, we calculate that in-merit hydropower generation rises to approximately 6.4 per cent of total generation in May-July compared to approximately 2.1 per cent in January-March. The actual impact of hydropower flows may be greater once flows from outside of the province are also accounted for.

coincident demand in each month of the year drive different requirements on the bulk transmission system. Put differently, growth in demand in the spring might increase the need for bulk transmission capacity to transport energy from a different source of energy than an increase in demand in the winter. Hence, allocating the bulk costs associated with meeting demand in a way that is consistent with cost causation principles requires that the methodology levies a fee in the highest demand periods across the whole year.

6.4.1.1. Alternatives Considered: 1CP and 4CP

238. We considered using a measure of single coincident peak across the year (1CP), or the four highest coincident peaks in the year (4CP) to recover demand-driven bulk system costs allocated to coincident peak.

239. However, a charge on 1CP or 4CP would be less reflective of bulk transmission requirements because it would not capture differences in how the bulk transmission system is used to serve demand in different seasonal conditions throughout the year (as illustrated in Figure 13). This is because the charges would recover costs based on demand in only one or four hours of the year, and would therefore only reflect the costs that demand imposes in a subset of the conditions that the bulk system is planned to meet.

240. Alternatively, using 12CP would be more cost reflective as it would reflect how demand at different times of the year drives bulk system costs, recognizing that the bulk system needs to be planned to meet coincident peak demand across different system conditions throughout the year.

6.4.1.2. We recommended retaining the use of 12CP but introducing a trailing average to the charge

241. While we recommend retaining the use of 12CP to recover costs associated with the bulk system allocated to meeting coincident peak, we also recommend that the AESO introduces a five-year trailing average to the charge. The introduction of a five-year trailing average improves the cost reflectiveness of the charge, thereby better meeting our evaluation criteria as we set out in Section 4. This is because an increase in a customer’s consumption at times of 12CP does not immediately translate to a change in the costs of the transmission system. Instead, the AESO plans the transmission

system to accommodate forecast consumption at times of 12CP. We understand that the AESO constructs this forecast based on historical consumption data over a five-year period.[90]

242. Consequently, customers' decisions to consume during times of 12CP in any of the previous five years results in a higher demand forecast and may drive the need for future transmission investments. Moreover, consistent consumption decisions by customers over a five-year period are more likely to impact the AESO's planning decisions than consumption decisions in a single year.

243. Therefore, we recommend that bulk system demand-driven costs are recovered by a charge levied on a five-year trailing average of customers' consumption at times of 12CP. The average would be calculated on a month by month basis, so that a customer's charge in January is calculated by examining its consumption at times of 12CP in January over the current year and the previous four years.

A. We illustrate this in Table 5 below. The charging basis in the current year "t" is calculated as the average of the customer's consumption at times of 12CP across the current year and previous four years. For instance in January the charging basis is 100 MW-month of consumption, which is the average of consumption during 12CP in January in the current year (110 MW-month), the previous year "t-1" (105 MW-month), two-years ago "t-2" (75 MW-month) etc.

Table 5: Illustration of Calculation of Our Recommended Trailing Average of 12CP

	Consumption at Time of 12CP					
Month	Year t-4	Year t-3	Year t-2	Year t-1	Current Year, Year t	**Charging Basis**
January	105	95	85	105	110	**100**
February	95	90	85	100	80	**90**
…	…	…	…	…	…	…
December	110	105	115	120	100	**110**

Source: NERA Illustration.

[90] AESO, AESO 2021 Long-term Outlook, June 2021, p. 13.

244. To avoid disruption, we recommend that the AESO phases-in the five-year trailing average to the 12CP charge. We illustrate how this phase-in could work in Table 6 below.

Table 6: Illustration of Calculation of Our Recommended Phase-In of the Trailing Average 12CP Charge

	Consumption at Time of 12CP in January						
Year Since Tariff Introduced	Year t-5	Year t-4	Year t-3	Year t-2	Year t-1	Current Year, t	**January Charging Basis**
First Year	110	105	95	75	105	110	**110**
2nd Year	105	95	75	105	110	100	**105**
3rd Year	95	75	105	110	100	90	**100**
4th Year	75	105	110	100	90	0	**75**
5th Year	105	110	100	90	0	85	**77**
6th Year	110	100	90	0	85	115	**78**
…		…	…	…	…	…	**…**

Source: NERA Illustration.

245. In the Table, we illustrate how the calculation of the charging basis for a customer would be calculated in January in each year following the introduction of the five-year trailing average on 12CP. A similar calculation would be made for all months.

A. In the first year of the new tariff being applied, customers would pay the 12CP charge as they do under the current tariff: entirely based on their consumption during the time of 12CP in each month throughout the year (110 MW-month in January in the example).

B. In the second year, customers would pay the 12CP charge based on their average consumption during the time of 12CP in the same month in the first year (110 MW-month) and the second year (100 MW-month). In this example, the customer would pay the 12CP charge on the basis of 105 MW-month of consumption in January in the second year of the tariff.

C. The average would continue to extend until the fifth year of the tariff, by which time the full five-year trailing average would be used to calculate the charging basis in the fifth year and all future years.

6.4.2. We recommend recovering the remaining demand-related costs using a charge levied on billing capacity

246. Having recovered the majority of bulk system demand-driven costs from a charge on 12CP, we recover regional system demand-driven costs and the remaining bulk system demand-driven costs allocated to non-coincident peak (see Section 6.3) from a charge levied on billing capacity, as defined under the Current Rate Design. Billing capacity is defined to be the highest of:[91]

A. the highest 15-minute metered demand in the settlement period;

B. 90 percent of the highest metered demand in the 24-month period including and ending with the settlement period, but excluding any months during which commissioning occurs (energization or testing of the facility prior to normal operation); or

C. 90 percent of the contract capacity or, when the settlement period contains a transaction under the Demand Opportunity Service rate, 100 percent of the contract capacity.

247. Regional system, demand-driven transmission assets are required to connect customers at individual sites to the bulk system and serve the requirements of customers within relatively localized areas. The driver of transmission costs in this context is the non-coincidental peak demand of customers within the local area, which determines the maximum demand that the localized system must be able to accommodate.

248. However, it may not be sufficient to consider customers' non-coincident peaks in demand. Customers may also have the *option* to draw power from the grid, up to their contract capacity throughout the year. Therefore, the AESO may need to plan the localized system to account for the possibility that the customer will draw power from the grid up to its contracted capacity.[92]

91 AESO, Consolidated Authoritative Document Glossary, July 2021, p. 6.

92 AESO, P1 – System Planning Report Transmission Tariff Work Group, 10 September 2019, p. 4.

249. A charge based on billing capacity therefore meets principles of cost causation by varying with both a customer's actual non-coincident peak demand as well as the customer's option to draw up to its contract capacity.

250. Similarly, we recommend recovering the bulk system demand-driven costs associated with non-coincident peak from a charge levied on billing capacity. As we discuss in Section 6.3, the bulk system may need to be larger than that required to meet demand at times of system coincident peak because it needs to meet non-coincident peak demand in different areas.

6.4.3. We recommend recovering the costs associated with accommodating flows of in-merit energy using an all-hours energy charge

251. We recommend recovering the costs associated with accommodating flows of in-merit energy from a charge levied on a customer's use of energy in each hour. We recommend that the charge does not vary across hours of the year.

252. As explained in Section 3.3.1 above, some transmission system costs are driven by the need for the AESO to plan to accommodate flows of in-merit energy. These costs arise because of a number of important features of regulatory arrangements governing the Alberta power sector:

A. First, we understand that the Transmission Regulation requires that the AESO plans to accommodate the free flow of in-merit energy in all normal operating hours.[93] As such, when customers buy energy from the wholesale market, depending on the prevailing location of the marginal generator, it may cause the AESO to plan transmission to accommodate the resulting flows of in-merit energy. It is cost-reflective for these costs of transmission associated with accommodating flows of in-merit energy to be recovered from a charge levied on energy consumption, because they are incurred in order to support the supply of energy from the wholesale market.

B. We have been asked to assume that transmission rates cannot vary by location, so there is no scope for these charges to be made more cost reflective by targeting them

93 Norton Rose Fulbright, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, April 11 2021, Assumption D. See Attachment 1A.

on energy consumption in particular locations, to reflect that the extra transmission costs associated with accommodating flows of in-merit energy may differ depending on where energy comes from and where it is consumed.[94]

C. Further, we have been asked to assume that the ISO Bulk and Regional tariff can only be levied on load customers.[95]

253. Recovering the costs associated with accommodating flows of in-merit energy from an energy charge promotes economically efficient decisions by customers over whether to consume power from the wholesale market, which needs to be transmitted over the AESO's grid. Customers would face higher energy costs if the Transmission Regulation did not require the AESO to plan for congestion free operation during normal operating conditions. Failure to reflect this cost in the transmission tariff would result in a tariff that did not reflect the full costs of supplying energy to customers in Alberta, as customers would be paying a total price for energy that did not reflect the transmission infrastructure costs incurred to provide that energy.

254. Therefore, recovering costs associated with accommodating flows of in-merit energy through energy-based charges satisfies principles of cost causation and promotes economic efficiency:

A. Explicitly classifying the costs associated with accommodating flows of in-merit energy to an energy-based charge sends more efficient price signals, accounting for the transmission infrastructure associated with supplying energy to customers while avoiding congestion. Recovering the costs associated with accommodating flows of in-merit energy from an energy-based charge increases the total price of each unit of energy supplied to customers to reflect the transmission infrastructure costs incurred to provide that energy.

B. Customers make consumption decisions based on the total cost of energy, comprising mainly the pool price and the cost of transmission. Classifying more costs to be recovered through energy charges may increase the all-in price of energy

94 Norton Rose Fulbright, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, April 11 2021, Assumption C. See Attachment 1A.

95 Norton Rose Fulbright, AESO Bulk and Regional Tariff Instruction Letter for Expert Report, April 11 2021, Assumption A. See Attachment 1A.

relative to the current tariff, which may encourage more efficient consumption decisions that reflect the costs of transmission.

6.4.3.1. Alternatives Considered: energy charge that varies depending on time of use or customer load factor instead of a flat energy charge

6.4.3.1.1. Alternative 1: Energy charge that varies by time-of-use

255. We considered whether there is a case for a time-of-use energy charge, which sets higher energy charges in higher demand periods, for example, by using peak and off-peak energy charges. This would be cost reflective if transmission costs associated with accommodating flows of in-merit energy were systematically more likely to occur in periods of higher energy consumption across the system.

256. However, we do not recommend this time-of-use structure be used for the energy charge, and instead we recommend that the energy charge should apply at a flat rate to energy consumption in all hours of the year, i.e. to total annual energy consumption because:

   A. First, to the extent that transmission investments costs are related to demand, and need to be sized to meet demand, it is logical for these to be recovered through a charge levied on the highest demand periods. However, as explained above, our Recommended Rate Design achieves this by recovering demand-related costs from charges on 12CP demand and billing capacity. The 12CP charge recovers costs when demand across the system is highest, whereas the billing capacity charge recovers costs when individual customers' demand is highest (or has the potential to be highest when levied on contract capacity).

   B. On the other hand, the costs recovered through the energy charge are associated with accommodating flows of in-merit energy, and as such are not related to demand.

   C. The costs associated with accommodating flows of in-merit energy may be incurred to avoid congestion in any hour of the day or time of the year. For example, the costs of accommodating flows of in-merit energy from wind generators are driven by times of windy conditions which may occur at all hours of the day. Some investments may also be incurred to ensure system stability in off-peak, low demand conditions. The costs associated with these investments are not systematically associated with hours of high or low energy consumption.

D. As such, there is no cost-reflective basis for a higher energy charge to recover more costs associated with accommodating flows of in-merit energy in hours of higher energy consumption. We do not have evidence to suggest that the costs of accommodating flows of in-merit energy systematically vary with changes in system energy consumption. Therefore, we propose to maintain a flat energy charge which is constant across energy consumption in all hours of the year.

6.4.3.1.2. Alternative 2: Energy charge that varies by customer load factor

257. We have also considered whether there is any basis to vary the energy charge by customer load factor or to include declining block charges for energy. The conceptual basis for both these types of charges is that customers who consume at relatively low load factors should pay higher per-unit charges than customers who consume at higher load factors. Such charging approaches can be cost-reflective if some fixed infrastructure costs associated with serving a customer do not vary in proportion to the customer’s consumption, such that high load factor customers or customers taking large amounts of energy from the grid do not impose any additional costs by doing so, when compared to a customer with a lower load factor.

258. However, for the same reasons as set out above, the costs associated with accommodating the flow of in-merit energy are unrelated to an individual customer’s demand or load factor. They are incurred to ensure the reliable operation of the transmission system, while avoiding congestion, as required by the Transmission Regulation. Because these costs are not related to the demands of any particular customer, but are related to the overall level of supply from the wholesale market, it is consistent with cost causation principles for these costs to be recovered from all kilowatt-hours supplied from the grid, without reference to any individual customer’s load factor. In other words, one extra kilowatt-hour supplied from the grid is just as likely to contribute to the transmission costs associated with accommodating flows of in-merit energy if it is supplied to a customer with a high or a low load factor.

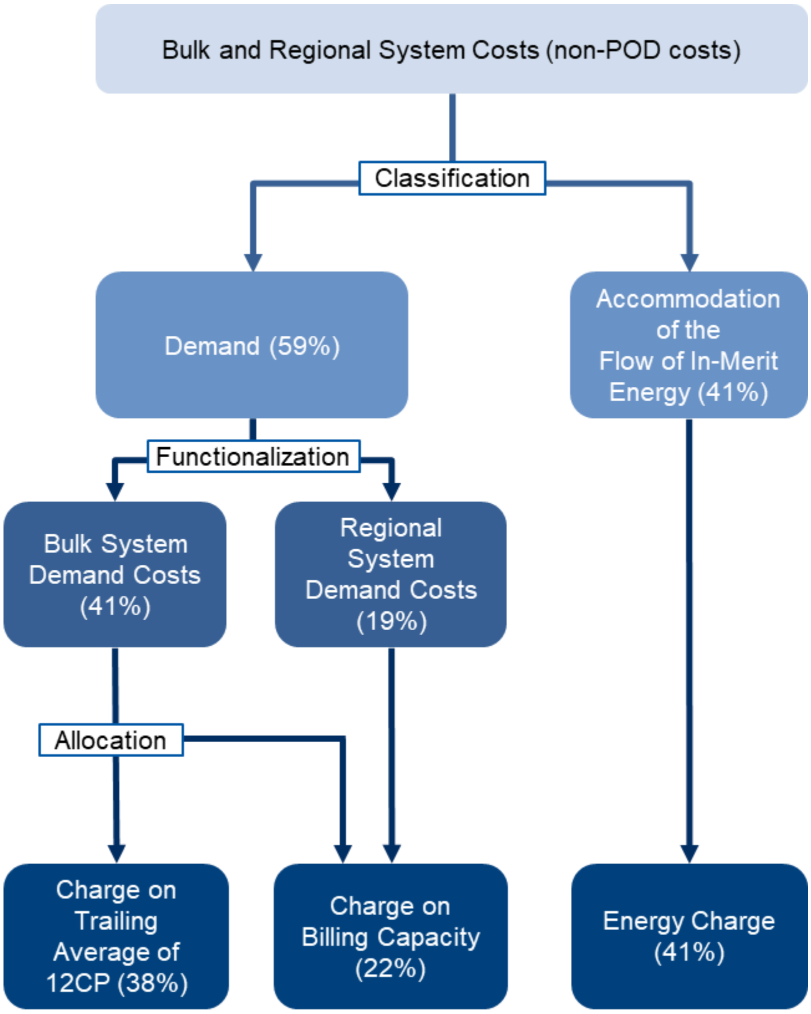
259. Therefore, we assess that it would not be cost reflective to vary the energy charge based on customers’ load factors. Instead, we recommend a flat energy charge which is the same in all hours of the year and for all customers, thereby better meeting principles of cost causation.

7. Section 7 - Summary and Results of Implementation

7.1. Summary of Our Recommended Rate Design

260. We summarize the steps required to calculate our Recommended Rate Design, as well as the percentage of costs allocated in each step (based on 2019 data) in Figure 14 below.

Figure 14: Summary of Our Recommended Rate Design



Note: Percentages calculated using 2019 data. Components do not sum to 100 percent due to rounding. Source: See Attachment 3A for calculations.

261. In the first step of our Recommended Rate Design, the AESO classifies non-POD costs between demand and those associated with accommodating flows of in-merit energy.

262. Given that generation connects at both bulk and regional system voltages, and that the AESO's planners adopt a holistic view that does not distinguish planning solutions purely on the basis of line voltage, we recommend that the AESO should classify costs

between demand and accommodating the flow of in-merit energy prior to functionalization of costs into bulk and regional system costs. This is because high voltage assets that meet demand reflect bulk system needs, while lower voltage assets that meet demand reflect regional needs. On the other hand, assets associated with accommodating flows of in-merit energy do not systematically vary in purpose by voltage. We recommend that the AESO:

A. Utilizes a minimum system approach to classify costs between demand and those associated with accommodating the flow of in-merit energy. We recommend that the minimum system be defined to reflect the size of the transmission system required to meet peak load in Alberta. Recognizing that the AESO's planning standards require it to plan a congestion free system under normal operating conditions, we recommend the full actual system be defined to identify the size of the transmission system required to accommodate the flow of in-merit energy in all hours. The size of the minimum system defines the proportion of costs classified as demand-related, while the difference between the actual and minimum systems defines the proportion of costs classified to accommodating the flow of in-merit energy.

B. Uses metered peak load and peak generation in each planning area in the reference year to estimate the size of the minimum and actual systems.

263. Using our recommended methodology and metered load and generation data in the AESO's planning areas in 2019, we calculate that approximately 59 percent of costs should be classified as demand-related, and approximately 41 percent of costs should be classified as those associated with accommodating the flow of in-merit energy.

264. After classification, we recommend that the AESO functionalize the pool of demand-driven costs using a similar method of functionalization as under the Current Rate Design, by using the net book value of assets delineated by voltage. We recommend functionalizing demand-driven costs using voltage to identify whether they are serving a bulk or regional function, because:

A. As higher voltage lines (240 kV and above) are more likely to be used to transmit power in bulk over long distances, between distinct areas of the system, the capacity requirement and costs of 240 kV lines are predominantly driven by demand at times of coincident system peak.

B. Lower voltage lines (below 240 kV) are scaled to meet non-coincident peak demand within a regional system, connecting those sites and planning areas to the bulk system.

265. Based on the AESO's calculation of cost functionalization in 2019, we functionalize 68 percent of demand-related costs as bulk and the remaining 32 percent as regional.[96] We apply this functionalization to the pool of demand-driven costs that we classified using our recommended minimum system approach.

266. However, we recognize that the bulk system may need to be larger than that required to meet demand at times of system coincident peak if peaks in demand in individual areas occur at other times. The costs associated with the additional bulk transmission assets that the AESO plans to meet this non-coincident peak demand is still demand-driven, but driven by non-coincident peaks in demand instead of coincident demand across the province. We therefore recommend that the AESO allocates bulk system, demand-driven costs between coincident and non-coincident demand-drivers as follows:

A. Use metered load data to identify non-coincident peak demand in each planning area, and the maximum of each area's contribution to monthly coincident peak demand across the year.

B. Sums each areas' non-coincident peak and maximum demand during times of system coincident peak demand across all planning areas.

C. Calculates the ratio between province-wide coincident peak and the sum of all areas' non-coincident peaks. This ratio determines bulk system demand-driven costs associated with meeting coincident peak demand. The remaining costs are associated with non-coincident peak demand.

267. Undertaking this calculation using 2019 data, we calculate that approximately 93 percent of bulk system demand-driven costs are associated with coincident peak

96 AESO, Appendix-E-Transmission-System-Cost-Causation-Study-2018-Update-Workbook xlsx, Sheet "Func Results 2019", Cells "D102-F102".

demand, and 7 percent of bulk system demand-driven costs are associated with non-coincident peak demand.

268. After allocating bulk system, demand-driven costs there are four pools of costs to recover from billing determinants:

   i. Costs associated with the accommodation of the flow of in-merit energy;

   ii. Regional system demand-driven costs;

   iii. Bulk system demand-driven costs associated with coincident peak; and

   iv. Bulk system demand-driven costs associated with non-coincident peak.

269. We recommend recovering the four pools of costs through three billing determinants:

   A. Recovering bulk system costs associated with coincident peak demand using a 12CP billing determinant, including a five-year trailing average to the charge to reflect that sustained high consumption at times of coincident peak are more likely to drive transmission costs.

   B. Recovering the remaining demand-related costs using a charge levied on billing capacity, as defined under the Current Rate Design, in order to reflect cost causation by varying with both a customer's actual non-coincident peak demand as well as the customer's option to draw up to its contract capacity.

   C. Recovering the costs associated with accommodating the flow of in-merit energy using a flat, all-hours energy charge. This approach promotes economically efficient decisions by customers over whether to consume power from the wholesale market, which requires the AESO to transport electricity over its grid and relieve congestion.

270. Using 2019 billing determinants, we calculate the resulting charges using our Recommended Rate Design in Table 7 below. We set out our calculations in Attachment 3A and provide a summary of our calculation procedure in Appendix A.

Table 7: Summary of Charges Under Our Recommended Rate Designs Using 2019 Billing Determinants

Recommended Rate Design	Units	2019	% of Non-POD Costs+
12 CP Charge*	$ per MW-month	5,894	(38%)
Billing Capacity Charge	$ per MW-month	2,119	(22%)
Energy Charge	$ per MWh	10.20	(41%)

** Note: 12CP charge levied on a five-year trailing average of 12CP but calculated using the same 12CP billing determinant as used under the Current Rate Design.*
+ Percentages do not add up to 100 percent due to rounding.
In order to ensure comparability with the rates set under the Current Rate Design in 2019, we calculate the charges under our Recommended Rate Design using the same non-POD cost revenue requirement and forecast billing determinants that the AESO used to calculate rates in 2019.
Source: See Attachment 3A for calculations.

271. Our Recommended Rate Design results in higher energy charges, and lower 12CP and billing capacity charges relative to the Current Rate Design.

7.2. Customer Response to the Tariff

272. NERA was asked by the AESO to estimate the likely customer response, by load including potential changes in self-supply outcomes, arising from moving to our Recommended Rate Design described in this Report from the Current Rate Design. Our assessment is focused on estimating whether the self-supply response to our Recommended Rate Design would likely create significant cost shifting to other customers in the short-run. Our analysis does not intend to estimate the long-run future of customer self-supply decisions in Alberta under any tariff.

273. In the report "Estimating Customer Response to Our Recommended Bulk and Regional Tariff Design," we describe our analysis of the anticipated customer response to the change in transmission rate design.[97]

274. We reach five conclusions in our analysis of self-supply, described in detail in our report:

A. Our Recommended Rate Design better reflects the long-run costs associated with usage patterns by customers, and should therefore encourage more efficient self-supply decisions by customers relative to the Current Rate Design. Following a

[97] Please see Attachment 4A. Posted to the AESO website on May 25, 2021. Available at https://www.aeso.ca/assets/Uploads/AESO-customer-impact-report-05-25-2021-v2.pdf.

change in the transmission tariff, customers may make different, and *more efficient*, self-supply decisions in response to a transmission tariff that itself better reflects the costs of transmission incurred to serve that customer's load. Self-supply decisions in response to cost reflective tariffs promote efficiency in the overall supply of electricity, and will tend to reduce the costs faced by the customers who purchase energy from the grid in the long-run.

B. Customer response to the change in tariff to our Recommended Rate Design is likely to be extremely limited. Using a model to identify the optimal self-supply decisions for 133 industrial sites in Alberta, we find that self-supply could increase under our Recommended Rate Design by up to 2,546 GWh relative to the Current Rate Design.[98] This is equivalent to a shift in costs from self-supplying customers to other customers of up to approximately 1.71 percent of the total revenue requirement for bulk and regional costs in 2018.[99] We set out our calculations and modelling procedure in Attachment 4.

C. The economic case for self-supply is likely to significantly worsen in the next decade due to rising gas and carbon prices.

275. Therefore, while our report finds that, the overall amount of self-supply by industrial customers may increase slightly following a change in tariff to our Recommended Rate Design, this impact is small and would in any event reflect a response to a more

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98 Our estimate of customer response is a total effect that includes any dynamic responses by customers to self-supply decisions of other customers. This "dynamic response" accounts for the effect of higher self-supply pushing up tariffs levied on the remaining demand, which may increase further the incentives customers have to self-supply.

99 In our customer response model, we estimate customer response across both 2018 and 2019. Our highest estimate of customer response occurs in 2018 and therefore we illustrate the cost shift using the relevant revenue requirement in 2018.

The numbers presented here differ from those presented in our report on customer response (presented in Attachment 4A) which reported an estimated customer response of up to 2,801 GWh and a shift in costs of up to 1.90 per cent of the revenue requirement in 2019. These differences are due to improvements we made to our modelling procedure. Most notably, we use the same billing determinant and forecasts of the non-POD costs recovered through the Bulk and Regional Tariff as the AESO used to set the 2018 and 2019 tariffs under the Current Rate Design, not the historical actual values of billing determinants and revenue requirement as in our previous report. This update ensures a more accurate comparison between the cases: (a) with the existing tariff in which we use actual tariffs for 2018 and 2019; and (b) the new tariff based on our Recommended Rate Design. It ensures we calculate tariffs for the two cases on the same basis. We also corrected the treatment of inflation for the aeroderivative combustion engine used in our analysis, which slightly raises the levelised fixed costs of the plant from $ (2019) 228 to 230 per kW, and the variable O&M costs from $ (2019) 4.39 to 4.41 per MWh. These changes are reflected in Attachment 4 which details our modelling procedure and calculations.

While our estimate of total customer self-supply does change by a small amount, our overall conclusions and commentary on analysis presented in both this Report and our previously published report on customer response do not change.

economically-efficient tariff structure. This impact should also be limited to the near term because unlike the status quo the 12CP incentive to invest in smaller self-generation options is much smaller, and the business case for larger self-generation options diminishes as the carbon price is expected to increase.[100] Moreover, our estimate of the increase in self-supply resulting from the implementation of our Recommended Rate Design may be an overestimate for a number of reasons. For example:

A. We ignore the potential for customers to increase purchases of power from the grid in response to lower 12CP charges in our Recommended Rate Design relative to the Current Rate Design.

B. We do not constrain the capacity of plants that customers can build to be above a particular size, or the mix of self-supply technologies that the customer can install. Hence, customers can build any amount (in MW terms) of either or both types of plant. This assumption makes the costs of self-supply appear more attractive than they would be in reality, as generation units typically come in standardized sizes, so each unit installed cannot be below a certain size.

276. Overall, our quantitative analysis shows that our Recommended Rate Design would not create significant additional cost shifting to other customers relative to the Current Rate Design in the short run.

277. Our report that sets out our findings in more detail is attached as Attachment 4A.

7.3. Overall Assessment Against Criteria

278. We assess that our Recommended Rate Design better meets the evaluation criteria set out in Section 4, relative to the Current Rate Design:

A. The Current Rate Design does not reflect past and future investments that the AESO plans to accommodate the free flow of in-merit energy, but instead allocates this cost primarily to the demand charge levied on 12CP. Our Recommended Rate Design identifies the costs of transmission incurred to accommodate flows of in-merit energy, as distinct from the costs associated with meeting peak demand.

[100] See Attachment 4A.

Therefore, our Recommended Rate Design better meets the principle of cost causation, as compared to the Current Rate Design. It will also send more efficient price signals regarding the value of energy, consumption at peak time, and non-coincident peak consumption in Alberta, by accounting for the transmission costs incurred to support the transmission of this energy to end users.

B. We assess that our Recommended Rate Design does not create significant disruption to customers as the structure of charges is similar to the Current Rate Design and are therefore understood by customers in the system. Moreover, any changes in the relative size of charges compared to the Current Rate Design result from moving to a more cost-reflective tariff design.

C. Our Recommended Rate Design is also more flexible and practical to implement for the AESO than the Current Rate Design. Our reliance on metered data means that we classify and allocate costs based on the actual use of the system, rather than relying on assumptions of appropriate assets to classify costs. As the use of the system changes between tariff years, the classification of costs in the tariff will vary to reflect such changes.

D. Our Recommended Rate Design also produces relatively stable tariffs across the years of data we have assessed in this Report, while still being tied to the actual use of the system. We demonstrate that both our recommended approach to classifying costs between demand and accommodating flows of in-merit energy, and our approach to allocating bulk system demand-driven costs between coincident and non-coincident peak demand lead to stable allocation factors over the past five years of data.

279. Therefore, we assess that our Recommended Rate Design addresses the shortcomings of the Current Rate Design and better meets our evaluation criteria set out in Section 4 and Bonbright principles.

280. Most notably, our Recommended Rate Design identifies and recovers the costs of transmission incurred to accommodate flows of in-merit energy, as distinct from the costs associated with meeting peak demand. Our Recommended Rate Design therefore rectifies the problem under the Current Rate Design whereby the majority of bulk system transmission costs are recovered through a charge on 12CP, irrespective of the

drivers of those transmission costs, resulting in an inefficient price signal of the costs associated with using the grid at peak time.

Report Submitted by NERA Economic Consulting Project Team.

Richard Druce

Richard Druce, Director

Appendix A. Calculation of Tariffs Using Our Recommended Rate Design

281. In this Appendix, we set out our calculation of the Bulk and Regional Tariff for 2019 using our Recommended Rate Design. We set out our calculations in Attachment 3A.

282. For the purposes of this calculation, we assume a Bulk and Regional Tariff revenue requirement in 2019 as shown in Table 8 below.

Table 8: Costs to be Recovered Through Bulk and Regional Tariff in 2019

	Units	2019
Bulk and Regional Costs	$m	1,572.32

In order to ensure comparability with the rates set under the Current Rate Design in 2019, we calculate the charges under our Recommended Rate Design using the same non-POD cost revenue requirement and forecast billing determinants that the AESO used to calculate rates in 2019. Source: Attachment 3A.

283. In the first step of our Recommended Rate Design, we classify costs between those associated with demand and those associated with accommodating flows of in-merit energy. We report this classification using our Recommended Rate Design in Table 9 below.

Table 9: Classification of Costs Between Demand and Accommodating Flows of In-Merit Energy

Classification of Costs	Units	2019
Demand	%	59.45%
Accommodating Flows of In-Merit Energy	%	40.55%
Classification of Revenue Requirement		
Demand	$m	934.81
Accommodating Flows of In-Merit Energy	$m	637.51
Total	$m	**1,572.32**

Note: Total may not match due to rounding. Source: Attachment 3A and 3B.

284. Next, we functionalize demand-driven costs into bulk system demand-driven costs, and regional system demand-driven costs using functionalization ratios, see Table 10 below.

Table 10: Functionalization of Demand-Driven Costs Between Bulk and Regional Systems

Functionalization Ratios for Demand-Driven Costs	**Units**	**2019**
Bulk System	%	68.29%
Regional System	%	31.71%
Functionalization of Demand-Driven Costs		
Bulk	$m	638.36
Regional	$m	296.45
Total	$m	**934.81**

Note: Total may not match due to rounding. Source: Attachment 3A.

285. Finally, we allocate bulk system demand-driven costs between those associated with coincident peak demand and those associated with non-coincident peak demand using allocation factors calculated using our Recommended Rate Design, see Table 11 below.

Table 11: Allocation of Bulk System Demand-Driven Costs Between Coincident Peak and Non-Coincident Peak

Allocation Factors for Bulk Demand-Driven Costs	**Units**	**2019**
Coincident Peak	%	92.82%
Non-Coincident Peak	%	7.18%
Allocation of Bulk Demand-Driven Costs		
Coincident Peak	$m	592.51
Non-Coincident Peak	$m	45.85
Total	$m	**638.36**

Note: Total may not match due to rounding. Source: Attachment 3A and 3B.

286. Having classified, functionalized, and allocated costs, we calculate charges by dividing the costs to be recovered by the forecast billing determinants upon which we recommend the AESO recovers those costs. We recommend recovering bulk system demand-driven costs from a charge levied on a five-year trailing average of 12CP, the remaining demand-driven costs from a charge levied on billing capacity, and the costs associated with accommodating flows of in-merit energy from a flat energy charge. Our calculation of charges is set out in Table 12 below.

Table 12: Recovery of Costs from Billing Determinants and Calculation of Bulk and Regional Charges

Costs Recovered from Billing Determinants	Units	2019
12 CP	$m	592.51
Billing Capacity	$m	342.30
Energy	$m	637.51
Total	$m	**1,572.32**
Forecast Billing Determinants		
12 CP	MW-months	100,532
Billing Capacity	MW-months	161,545
Energy	GWh	62,524
Charges Under Our Recommended Rate Design		
12 CP Charge*	$ per MW-month	**5,894**
Billing Capacity Charge	$ per MW-month	**2,119**
Energy Charge	$ per MWh	**10.20**

** Note: 12CP charge levied on a five-year trailing average of 12CP but calculated using the same 12CP billing determinant as used under the Current Rate Design. Total may not match due to rounding. In order to ensure comparability with the rates set under the Current Rate Design in 2019, we calculate the charges under our Recommended Rate Design using the same non-POD cost revenue requirement and forecast billing determinants that the AESO used to calculate rates in 2019. Source: Attachment 3A.*

Qualifications, assumptions and limiting conditions

NERA Economic Consulting ("**NERA**") was instructed by Norton Rose Fulbright LLP to produce this report providing our expert opinion on NERA's Recommended Rate Design for the Alberta Electric System Operator's ("**AESO**") Bulk and Regional Tariff. The primary audience for this report includes the Alberta Utilities Commission, and the AESO. NERA shall not have any liability to any third party in respect of this report or any actions taken or decisions made as a consequence of the results, advice or recommendations set forth herein.

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